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WORKSHOP

RENEWABLE TRANSMISSION

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COMMITTEE MEMBERS PRESENT

John L. Geesman, Commissioner, Presiding Member

James D. Boyd, Committee Member

Melissa Jones, Commissioner Advisor

Mike Smith, Commissioner Advisor

STAFF PRESENT

Don Kondoleon

James Bartridge
Jim Dyer
Electric Power Group, Consultant

ALSO PRESENT

Jim Caldwell, PPM Energy

Jeff Miller
Dave Hawkins
California Independent System Operator

Jan Strack, San Diego Gas and Electric

Bob Zavadil, Utility Wind Interest Group

Jorge Chacon, Southern California Edison

Chifong Thomas, Pacific Gas and Electric

Cliff Murley, Sacramento Municipal Utility District

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P R O C E E D I N G S

CHAIRPERSON GEESMAN: I think in the interest of time it would be best to just go forward.

MR. BARTRIDGE: Good morning. Welcome to the Renewable Integration Workshop, Operational Integration Number 2. Out the door to your left are the restrooms. Upstairs, if you haven't been here before, is a snack shop and coffee available, and the alarm, the door to the left-hand side is alarmed, so be careful, don't step out that door. And with that --

MR. KONDOLEON: With that, we're ready to begin the program.

For those that weren't here, we actually had a workshop, Workshop Number 1 back in early February. There was a background piece that was prepared by the Electric Power Group for the CERTS team that was released at that time. We took comments, both at the workshop and written comments after the workshop. Since that time the Electric Power Group has prepared another document. That document has been posted on the website, and we are again taking comments here at this time, and also will be taking written comments for a period of about two weeks. We'll speak to that later, towards the end of the program.

Let me move on and have Jim Dyer, who will speak to the work that's been done. We've got a number of presentations that will be provided here today, and we look forward to your active participation.

Thank you.

MR. DYER: Good morning. It's a pleasure to be here. Thank you, Commissioners, for inviting us. And it's our opportunity to share our assessment on the reliability and operational issues with the integration of renewable resources. One, it's, it's a key goal and objective for the state, and I think there's a lot of work that needs to be done and hopefully we'll, we'll support and give some suggestions to that.

First, I'd like to just thank Don Kondoleon from the staff for his support and, and contributions in working on this project, and also Joe Eto, from the CERTS program office.

As Commissioner Geesman indicated, we have a lot to cover today, so I'm going to move along here. Let me just give you a brief outline of how the, the next couple hours will flow. I'll spend a few minutes talking about the project objectives and the activities that this team has been involved in. We'll recap the February 3 workshop very briefly.

Following my brief discussion on the workshop, we have the pleasure of two presenters. One, Jim Caldwell from PPM Energy, who will talk about the findings from his visit to E-ON Netz in Germany. We'll then go to Jeff Miller, who will give us a quick update on the low voltage ride through standards that have recently been voted on the WECC.

Following those two presentations, we'll have the pleasure of, of listening to Bob Zavadil, from -- who's representing the Utility Wind Interest Group, and talking about wind forecasting, the state of the art and, and his experience in that area. I'll come back, and then we'll talk about the present, the purpose of today's meeting. We'll summarize the resource, renewable resource development and the characteristics, we'll talk about our updated issue list, summarize the different issues that we did analyze. We tried to quantify the issues where possible and, and put a matrix on them and do an assessment.

We'll then discuss and get into some of the policy options and solutions that we're suggesting. Each one of these solutions and, and policy options, we've identified owners and, and activities that need to be done, follow-up work. We'll, following that we'll get into a, a stakeholder panel discussion to see how the stakeholders are reacting to what we've put in our report as far as suggest solutions and policy options.

We'll then have a, an open comment period where each and every one of you have, will have an opportunity to speak, and we'll close, Don Kondoleon will be back to close the day with the next steps.

The, the objective of this study really was to go out and, and find out what's going on in, with renewables, and, and how different organizations are trying to integrate them in the Western United States and the rest of the nation, and even in other parts of the world. So look at some paper studies, catalog some experiences associated with integrating renewables. Also, get into the trenches and talk to those that have been involved in it. In California we have had renewables for, for over a decade or two. We've conducted stakeholder workshops, identified solutions, options, and suggested actions. And then our final objective of this project is to prepare a final report that we'll integrate with the Commission's IEPR process.

To date, the activities of the team are, one, we, we've reviewed an extensive amount of studies and, and reports. And again, as we talked to different organizations and different representatives from, from developers and such, we kept getting more and more insight as to where we might be looking to find additional information. There's a ton of information out there. You can get a -- real quick. From that information, and talking with individuals, we identified some gaps which were included in our operational and reliability issue list.

We did participate in several workshops, renewable resource workshops, both in the state and, and other parts of the nation, as well as conferences. We participated in the stakeholder interviews, talking to both developers, the investor owned utilities, municipalities, and the California ISO. We did give a presentation at the February 3 workshop, again sharing the issue list and, and getting feedback from the stakeholders, and we appreciate the feedback we did get.

We have performed some analysis where data was available, and where we felt we could quantify the issues we have done that. And we have developed a, a draft report which includes solutions, policy options, and suggested actions that might help solve or mitigate the integration reliability issues. And we're here today to seek the stakeholder input on, on those issues and, and solutions.

Recapping the February 3 workshop. As a result of the workshop there was some concern expressed regarding how we characterized the, the shadow reserve on the E-ON-Netz transmission grid in Germany, and the current status of the low voltage ride through standards that are being developed in the U.S., and more specifically in the Western United States.

Comments were made that the reliability and operational issues identified were attributable to all resources and not, and not assignable solely to renewable resources.

The project assessment should be focused on, on California and the California issues, and how it might be integrated in California. And we did receive no additional issues as a result of that workshop.

With that, let me open the floor up. We've got -- or, not the floor. We have three presentations, as I indicated earlier. Jim Caldwell will be talking about his visit to E-ON NETZ and what he found. Again, very brief presentation. And then we'll turn it over to Jeff Miller, who'll talk about the low voltage ride-through, and then Bob Zavadil. So, Jim.

MR. CALDWELL: First of all, the agenda lists me as, as PPM Energy, but also for the California Wind Energy Association. And I can assure you that neither Nancy Rader or I particularly appreciate the, that affiliation. I'm not affiliated in any way with the California Wind Energy Association, so we could just sort of close the period there at PPM Energy, for the record.

At the February 3rd workshop, I noted

that I had previously scheduled a trip to Germany and that part of that trip to Germany was going to include a visit to E-ON, and I offered the Commission and I offered this proceeding to, to share the results of that trip, and so that's what I'm here to do.

I met the E-ON folks at the E-ON corporate headquarters in Dusseldorf on February 14th. We had about a three-hour meeting in the afternoon. And then that was, that was, I think, a Monday. On Thursday, February 17th, I also met a group in Berlin. It was DENA, which I don't remember the words, but it's the German equivalent of the, of the Department of Energy. It's the department of something or other, natural something or other, in German.

And DENA is conducting, and is conducting a, a study of what's going to be required basically to turn the German grid upside down and put somewhere in the neighborhood of 40 to 50 percent wind on the grid in Germany. And Germany is about a third of the way through that process. Currently they have about 16,000 megawatts of wind connected to what is about an 80,000 megawatt grid in Germany. The findings so far I think are relevant.

The first thing I would say, or the first finding that we said is there's been no change in operating reserves from the 16,000 megawatts of wind on the current grid. Absolutely none. That there has been no change in the required primary reserves, which is roughly equivalent to what we would call AGC, or Automatic Generation Control. There has been no change to the secondary reserves, what we would call Quick Start, and no change to tertiary reserves, which is what we would call something like replacement reserves.

Second finding is the word "shadow generation", which appears in the E-ON report, is not the equivalent of operating reserves. It is simply mathematically one minus the effective load carrying capability, or one minus the capacity credit for wind. So to the extent that the report says that shadow reserves of, of 80 percent, all that is is one minus .8, or 20 percent saying that the capacity value of wind is about 20 percent of the nameplate of wind.

The third major finding I think that's relevant here, is that the E-ON report, which,

which said that they required 50 to 60 percent of the wind nameplate generation, as in the word they used was reserves in that word, that, that -- and, and the phrase is 50 to 60 percent of wind nameplate capacity that is actually used. And all that means is, is that's the amount of flexible generation that needs to be available to be re-dispatched in order to do the system balancing. And that amount of flexible generation happens to, at the current, current market structure and the current wind penetration, be about the same as is required to follow the daily ramp. In other words, there's been no change, no necessity to have dedicated flexible generation to, to handle that amount of wind on the system.

In the future, as they go from something on the order of 16,000 megawatts of wind to something more than -- more like 50,000 megawatts of wind, that is the area in which they have said that they will either have to change the market structure or they will have to physically add resources, and they're suggesting that maybe something on the order of 2500 megawatts of wind -- of, excuse me, of flexible generation for something like the 50,000 megawatts of wind is what they would need. However, they could obviate that need simply by changing their market structure.

So other issues that, that I found when I was there. The first one is that, that of the imbalances that are created by wind, 50 to 60 percent of those imbalances simply go away if Germany does nothing other than consolidate its four separate, what we could -- what we would call control areas. The control areas in Germany are now set up administratively, and they follow basically the lines of, that the allies post World War II, so the American sector is the E-ON NETZ sector. And those political boundaries bear no relationship to the electrical boundaries that, that the grid would see, and therefore there's a lot of balancing that goes on between these administrative boundaries that actually just disappears if they do nothing but, but let them run. And then instead of balancing them out every 15 minutes, let them balance out over, over a daily period.

CHAIRPERSON GEESMAN: How, how would you compare that to the WECC in this country?

MR. CALDWELL: Well, I, I think the --

I'll get to that in, in sort of my lessons learned. But I think what it says is, is that in many cases that the control area boundaries are the things that, that determine what is the apparent cost and the apparent difficulty with balancing, and that Kirchoff's Laws don't, you know, don't necessarily follow the accounting rules, and that you don't need to do things to balance the system. And that a lot of the, the, the so-called problems with balancing comes from simply having too many too small control areas.

CHAIRPERSON GEESMAN: No, Kirchoff tried to get westwide RTO and --

MR. CALDWELL: Yeah, he had about as much luck as Pat Wood did, I guess, with --

CHAIRPERSON GEESMAN: You've never seen the two of them in the same room at the same time, have you?

(Laughter.)

MR. CALDWELL: So I think the, the second, the second issue that I think you need to understand when you're talking about Germany is, and again, this is an accounting issue, is that, is that the money is a lot of the cause of these problems, and the way the money flows. In

Germany, the, the wind is definitely significantly above market price or avoided cost of what we would call in that sense. The, the German tariff is called a feed-in tariff, and there are some 900 distribution companies in Germany. And they pay 11 cents a kilowatt hour, a little bit more than 11 cents a kilowatt hour, for every kilowatt hour of wind that comes in from about 150,000 owners of wind turbines in Germany.

Basically, the way, the way it was done here in the 1980s, a lot of tax-driven investors who, who distribute the ownership. The wind there in Germany is almost all hooked up, at least to date, one, two, three turbines at a time on individual farms, and it comes in through the distribution grid. It is not large farms that come in at transmission level. So these 900 distribution companies pay 11.1 cents a kilowatt hour, and they get immediately reimbursed by the four control area operators or transmission owners, of which E-ON NETZ is one.

Then those four companies get reimbursed out of an uplift on all electricity sales from the country. So in E-ON NETZ' particular situation, they have about 45 percent of the wind, and they only have 29 percent of the nation's electricity sales. So they have to get redistribution money from their competitors, from their other control area operators, and you can imagine what that proceeding is like. And one of the major things in that proceeding is that anything that the utilities can claim to be wind integration costs comes off the top, and they get to keep that before it goes into this redistribution formula. So that the, the four utilities are motivated to raise what we would call these integration costs, and they're motivated to try to call anything they can and assign it to this category, this accounting category, because they get to then keep that money and don't have to give it to the other folks. And so I think that in general, that is the kind of thing that, that is the reason why you read the reports the way they're, the way they're written and the way they come out that way.

I believe if this Commission cares to pursue the German experience in any further detail, that it would, would behoove us to actually hire somebody and do a, a more thorough job. But you're just not going to find it out by reading the English translation of German reports or by, by, frankly, by simply my, my travel visit.

I do think that the lessons learned, or what I would take away from the experience of looking at what's going on in Germany, and this is also colored by Spain, Denmark, and other places in Europe which have high wind penetration, and the lessons learned for California I think are three. The first is that size matters. As we said, a lot this comes from the vulcanization of the control areas, not necessarily from the idea that the system itself needs balancing. So the accounting is what's ruling, in many cases, the issue.

In California, that's obviously an interesting point. With, with, on the one hand, the move to consolidate control areas through the California ISO, and on the other hand, the move to withdraw from the California ISO by the municipal utilities and create what is essentially a parallel grid with parallel -- with parallel balancing authorities, and that's going to be a problem. That's a negative, in terms of, of wind penetration or renewable penetration, or, for that matter, for reliability or cost of running the grid, that the more control areas you have, the harder it's going to be.

I think the second, the second main take-away from the German experience is that if size matters, that what matters more is the market structure and the tariffs, and that, that in many cases, that what we're doing is we're confusing the accounting rules about how to allocate fixed cost amongst a certain set of, of both players, with the actual electrical requirements of the system and the, and the system balance in, in total.

And so the market structure and the tariffs matter. The Germans have basically said that there is essentially no way that they can achieve their goals of getting to 50,000 megawatts of wind unless they change the market structure and the tariffs. And if they do change the market structure and the tariffs, then a lot of these issues tend to go away.

The third lesson I think that, that we can take away from the German experience is that in the end, Kirchoff's laws do rule, and that the system must balance. And the electrons don't know the difference between all of these control area operators, and so forth. And so that the grid flexibility, which in this case I think we can read the stiffness of the grid or the amount of transmission, is ultimately going to determine what the wind penetration limits are, what the cost to, to, to change the, the generation mix in California so that the, that what you will see in terms of cost is not necessarily operating reserves, is not necessarily a whole lot of generation related costs it's associated with.

What you're likely to see, should we get to penetration levels of maybe the 33 percent kinds of numbers that we're talking about as a goal, is really some transmission investment. Transmission investment to be able to spread those, those imbalances and spread the, the ancillary services to evenly distribute them on the grid.

So I think those are the three lessons to learn from California. Thanks.

CHAIRPERSON GEESMAN: Thank you, Jim.

MR. DYER: Next, we'll have Jeff Miller from the California ISO speak on the low voltage ride-through.

MR. MILLER: Well, good morning. Pleasure to be here to talk with you about WECC's recently adopted low voltage ride through standard. For those of you have ever heard me talk about wind issues before, you're probably getting tired of seeing this slide. I know Mark Smith keeps threatening he's going to charge a royalty for further use of it.

But this, I, I never get tired of it. To me, it's just amazing to see this big a turbine rotor. This is, I think, a 1.5 or 1.8 megawatt unit. I was looking in the wind report at the five megawatt units, and it would be, you know, nearly double this diameter, really impressive.

When WECC started getting interested in, in the wind turbines and low voltage ride through, when it became apparent that through all the RPS's and so on that we were going to have a large amount of wind generation development. With a couple thousand megawatts across the western interconnection as, as exists today, it's, it's not that critical if a 100 megawatt wind plant trips off here or there. That's not a big problem. And recognizing that most of the old technology were induction generators, there wasn't much they could do to avoid it.

So it really wasn't an issue until we started looking at potential wind penetration levels much greater than that. You know, if you're looking at ten, or some of those guys have looked at 20,000 megawatts of new wind generation, then all of a sudden it becomes a reliability concern to WECC. We don't want to align the trips somewhere and then all of a sudden generation starts tripping, your frequency drops, you'd start losing load, and you could go to cascading outages. We want everything to be controlled. We want to know what's going to happen.

And we, one way we can do that is through the development of reliability standards that require the equipment to stay in during certain disturbances. And that's the whole point of, of WECC's standard. It, it's focused on requiring generation to stay in service during specified voltage excursions which, which we think are reasonable. We started a, WECC started developing the standard in the fall of 2003, and just, just recently, last month, it was approved by the WECC Board.

The basic requirement is, is that the turbines have to stay in there. Voltage can drop if you have, you know, a three-phase fault at a substation voltage can go to zero, and we'd like all generators to be able to stay in there until that, that fault would be cleared. It wasn't reasonable for wind generation technology. We, we took from the German E-On standard that Jim just talked about, and from the FERC, the FERC proposed rule, a 15 percent requirement which the wind generation community felt they could live with. And in looking at it from a reliability perspective, WECC felt that that might be adequate.

We also have something called a disturbance performance table in WECC which has all different types of outages that might exist on the system, and then it has specified there certain allowable voltage excursions for different timeframes right during the disturbance, within a few seconds afterwards, and then when you get to a steady state longer term period. And I'm not going to go through that here. I have a little chart that kind of compares what the, what WECC's doing to, to what's been proposed in the German E-ON standard.

We measure the voltage at the high side as it connects to the grid. You can argue about exactly where that point is. It's pretty hard to define specifically, so it's a fairly general description in the WECC standard.

One of the big concerns with the WECC standard was, well, if you just put it in place now, a lot of equipment's already been ordered that can't meet the standard. Does that mean we have to, you know, void the contracts, put all the equipment, you know, in the salvage yards and, and buy all new. And that was an unreasonable position, so based on input from all the WECC members and the wind generation community, we, we were told that maybe six months was an adequate lead time. Some people wanted a year. We went with the, with a full year lead time before the standard actually goes into place.

So it applies to generators that initially connect to the grid in March, after March 1st of 2006.

MS. JONES: Can I ask you a question. Does this apply just to wind generators, or is it applied to all generators?

MR. MILLER: The WECC standard applies to all generators.

MS. JONES: Thank you.

MR. MILLER: The, the FERC standard is,

and we'll talk about that in a minute, that applies just to wind generators.

While this was going on at WECC, FERC was actively involved in developing a standard of their own. This is kind of a new thing for FERC, and WECC and NERC are a little concerned about this change of events. But FERC usually doesn't develop reliability standards, but they, they started with a couple, and this was one. They proposed Appendix G of the -- generator interconnection policy, where they have a specific low voltage ride-through standard.

The FERC standard is, is more stringent than WECC's. Now, FERC also gives the ability of, of an area to adopt a less stringent standard, as long as it's done in a non-discriminatory way, so it may be that the WECC standard is what, since it is less stringent, may be what determines the requirements for wind generation, rather than FERC.

The FERC standard looks similar, because it, it takes a lot from the German E-ON standard, as well. Low voltage ride-through capability of .15 per, or 15 percent, .15 per unit. I think rather than go through this, what I'll do is I'll just describe it in the chart.

This is the, the FERC standard, and what, what we have on the lower axis here is the timeframe from zero up to four seconds. And then we have the voltage that the generators would see at the, at the high voltage side of their transformer. So the FERC standard says okay, you have a disturbance. The voltage goes to .15 per unit. It can stay there for .625 seconds. This is a long, long time in the power system. It may not sound like much time, but when you're at that level of voltage that's a very extreme disturbance for a power system. And then the voltage recovers and goes up to about 90 percent of where it was originally, and stays there steady state for a long term. That's the, that's the FERC proposed standard.

If you look at the WECC standard on top of that, they say okay, we're doing the same thing. At the disturbance the voltage goes to .15 per unit, but it only stays there for the duration of the fault. Now, for a typical fault on the volt system might be something like five cycles, you know, if a cycle is a 60, so 560 is sort of a second, much shorter period of time than the .625

seconds in the FERC standard. And we assume the fault's cleared, and then you go through a transient period where the system's bouncing around a little bit. You get some voltage, transient voltage dips, which just happen for a shorter period of time.

The WECC standard would require that the generator be in there for about a 30 percent transient voltage dip. And then it goes into steady state, and the WECC standard for the more severe contingencies require that the, the generators stay in there at the same 10 percent drop that FERC's proposed.

So there are some similarities, some differences. In general, the WECC standard's less stringent.

Some differences. WECC standards applies to more units, they have a 10 megawatt requirement, whereas FERC has 20 megawatts. As, as came up earlier, WECC's standard applies to all generation, FERC is just to wind generation. WECC, WECC was trying to be totally non-discriminatory. I guess I, am I calling FERC discriminatory, I guess so, with that statement. But WECC was trying to be non-discriminatory.

But one thing that's come up in WECC is, is a lot of us feel that maybe for, for non-wind generation, for a typical synchronous generator, we might need a more stringent standard. We're looking at that right now. For years and years, all of the studies have assumed that, that synchronous generators will stay in, in sync with the system at, at zero voltage for that short period of a fault. And looking at it more closely, that may not be true. But we may need, we may need some kind of standard that's a little stricter than this for the synchronous machines, but we may not be able to, to get to the zero per unit voltage.

That's all I have. Are there any questions?

CHAIRPERSON GEESMAN: In California, have there been, I guess what I'll call low voltage islands of vulnerability?

MR. MILLER: We have some graphs, and I've gotten some graphs from our operations folks that show some dips in output that we think may be due to low voltage, it may be due to high wind speeds and the units tripping out, but we really, we really can't say that it's been a, a serious problem on the California grid. This is more preemptive of future problems --

CHAIRPERSON GEESMAN: Sure.

MR. MILLER: -- and that's why, you know, the existing generators that are out there, we're not intending to require that they comply with this standard. They would only need to comply if they were to replace their generators with newer technology.

CHAIRPERSON GEESMAN: Thanks.

MR. MILLER: Thank you very much.

MR. DYER: Appreciate that, Jeff. Thank you.

Now we'll go to Bob Zavadil, who will give us a presentation on wind forecasting.

MR. ZAVADIL: Thank you, Jim.

Good morning. It's good to be here. My topic this morning is wind generation forecasting, but I need to preface my presentation by saying it's going to be from what I would consider to be the application side. There's a lot of very good fundamental research and development going on amongst the meteorological companies that are looking at this problem, but for it to be a value in assisting with the integration of wind generation we need to understand how that maps to the processes and procedures we use to operate the grid. So I'm not a meteorologist.

Oh, okay. I guess copies of my presentation will be circulated here very shortly. I apologize. I came out on, on somewhat short notice.

With regard to the power system operation and wind generation, fundamentally wind generation is an energy source, and it's got a lot of attractive attributes from that perspective. With regard to power system operations, we tend to think in the capacity framework, and that's completely necessary because of the requirements for high reliability and maintaining the security of the system.

So when we look at wind and its, and its unique characteristics, our, our thoughts go to how does that increase the net load variability. If we think of wind and -- if we think of the net load as the actual load minus the wind generation, in the aggregate, what does that look like, because ultimately that's going to drive what I need to do operationally.

A big part of operating the power system is to plan ahead, because if I have notice of things and early warning, I tend to have more options available and can make better decisions. So with regard to wind generation over forward periods, how does that increase the overall uncertainty that I deal with, because certainly load for the next day or the next periods is not known perfectly.

Since wind is an energy source there are some contacts where the amount of energy you might get over a period is of concern. If you're a utility that is buying gas daily to meet electric generation requirements as well as serve residential load, how much wind energy comes in over a period might be a critical input to my, my process for nominating gas.

From the power system perspective, the issues are categorized as either cost issues or reliability issues. And in some cases with wind generation there are areas where, where those overlap. So the integration cost from a cost based perspective, not with regard to a wholesale power market, is how much does it cost me to serve the -- extra does it cost me to serve the load not served by wind. I've got to serve so many megawatt hours that wind is not going to serve. If I have to manage this additional uncertainty and variability will it cost me more to serve that same number of megawatt hours.

So the, the particular elements of that, we've heard on many occasions in these types of conferences the reference to, you know, conventional and ancillary services regulation balancing. But then we have some costs that don't, aren't so easily categorized that relate to especially like the uncertainty of wind generation going forward.

The utility wind industry group has been tracking a number of studies that have been conducted over the last five years now, and there's more of them every day, and in a summary paper from 2003, so this is slightly out of date, kind of provided a thumbnail of what has been found so far. This table is a little bit complicated, but the, but the summary is that for the penetrations of wind studied in all these contexts, the costs certainly were not zero with regard to additional costs of integration, but they were, they were relatively modest. A, a number of different approaches, methodologies, emphasis in the particular studies, but people seemed to be for these penetrations which would range 10 to 15 percent, maybe up to 20 percent. There's some agreement that the costs are modest.

So when we have significant wind generation on the power system, from an operations standpoint what we see in terms of the daily load curve can look substantially different. And that's one of the issues, one of the challenges we have in that when we talk about very large amounts of wind generation in a particular scenario, we, as system engineers, simply don't really know what that's going to look like. And so I think in, in a lot of cases the uncertainty just with regard to specific quantitative impacts, as well as our fear of the unknown, can, can tend to bias us much towards the, the conservative side of things, and, and that's necessary. But it's also necessary that we, we develop some better pictures on what wind is going to look like in significant quantities.

If we look at some particular issues like how the net load pattern in a control area, or in a balancing authority per the new NERC terminology, actually looks, I obviously in the morning need to have generation available to follow the load as, as it rises in the morning pick-up, and the same time at night in the turn-down I need to be able to back off generation. When we throw wind into the mix, substantial amounts of wind, that behavior can change.

A couple of, of graphs from a fairly detailed study, and you can see in this case is the morning pick-up, and now with, with wind in the picture, which is the, the blue graphs, and it's, it's the net, not just wind alone, I have many more occasions of a super ramp that I might -- that I will need to be able to deal with. In the evening, when -- or overnight, when things are running flat, there will be occasions when I need to back down the extra generation as wind comes up during the night.

So these are, are challenges for operators that they need to understand, they need to have forewarning about, they need to have practices and procedures available to give them the control flexibility to, to actually deal with these things.

I should note, though, that if you look at this chart a little more carefully, it doesn't mean that every morning your ramp is going to be increased. It's going to, overall, this is, I think, 87, 60, or this is a, a year sample, so I have, I have essentially 365 hour ending sixes there. And on a number of occasions the ramp is increased, but there are a lot of days when the ramp isn't increased. And, in fact, there are some days that wind generation comes up with load and I don't ramp at all. I actually have to back down a generation a little bit. So it's the, it's the sum total effect over the period here that is of, is the primary question.

If I look at a little finer scale within the hour, wind generation is variable. I don't like to use the term intermittent myself, but it's certainly going to behave differently than a, than a schedule-able conventional power plant. So the question becomes within the hour on, say, ten minute increments, with a large amount of wind generation in the system, what does the net load look like. Do I have to do anything differently within the hour.

One of the things we seem to be finding when we are studying larger amounts of wind generation, 10, 15 percent. Those scenarios are necessarily spread out over a decent sized geographical area. And when you start to spread out over that area, the effects at very short time intervals kind of wash out a little bit. So what we've been seeing with regard to this inside the hour kind of interval is that significant amounts of wind generation do have, do appear to have some impact, but it's relatively modest. The bottom curve shows the distribution of the, of the changes on a ten-minute by ten-minute basis for control area load with, I think that's 1500 megawatts of wind in a, in a 10,000 megawatt control area.

And so I can certainly see the effect, but if I, I look at it a little more carefully, and it's, it's sort of a crude way to present it, while there are some much larger changes that do occur, the number of them over the course of a year is not so great. And if you look at it in terms of control performance or additional fast ramping capability, the effect is, is, in the end, relatively modest.

With regard to next-day uncertainty, and this is where we really start getting into the forecasting issues, as it stands right now the,

the forecasting companies think they can perform, deliver a next-day forecast. This would be 18 to 41 hours ahead. This would be your scheduling for the next day in the morning. Over the course of the year that would have a, have a 15 percent mean absolute air, okay, on an hour by hour basis for that, for that duration. Out to 72 hours, is what they're looking at right now.

However, if you look at the, the forecast, in the forecast there in more detail, you'll see that there can be some very large hourly errors. They might have the energy for the day spot on, but might miss the timing of a large funnel passage, which maybe isn't so important for California but for places in the upper midwest is a, is a major factor in, in driving wind generation. You can get into weather patterns that are difficult to forecast. So for periods of time, your next-day wind generation forecast could be, could be much poorer.

Now, this is not entirely different than we see with load. We just have much more experience with regard to load forecasting, especially in a, in a particular control area. However, when we, when we consider both the wind generation forecast error and load forecast error at the same time, because we're interested in net control area demand, what we have to do with all of the resources, we find that there don't seem to be real strong correlations between the wind generation forecast error and the load forecast error in the data that we've looked at. So that has the net effect of, of diminishing the effect of the wind uncertainty. If you consider them to be random variables, the, the errors don't add arithmetically, so I end up with a little larger uncertainty, but not so great.

Two examples. The first is from a, a WECC utility actual load forecast errors and, and projected wind generation forecast errors. You can see from the blue bars that my hour by hour error the next day is going to be increased somewhat. Now, you cannot go immediately from this sort of impact to what that -- to a translation to cost. But we can see that there is a modest impact.

The bottom chart is from the GE study for the New York ISO, and they find there is that with regard to your forecast peak load, adding ten percent wind generation -- it's a 33,000 megawatt system -- only slightly increases the, the forecast peak error for the next day.

The important thing, though, with regard to forecasting, and I'll use the example from the GE study. They looked at the impact of wind generation on the power market, on the spot prices, locational marginal prices in New York state. And they ran through a couple scenarios. The first one was just ignoring wind generation in the next-day unit commitment, which establishes the locational marginal prices for all the players. And then they compared that to a scenario where you use the next-day wind generation forecast of the 15 percent, you know, mean absolute air some hours, very high air. And what they found was that the variable cost reduction increased by $95 million for the year when you forecasted wind generation.

And if you follow this through it's kind of interesting, because actually the load comes out better if you don't forecast wind, and that's because of the market flaw. If you don't forecast the wind for the next day, the market players are responding to the wrong information and you have more generators lining up to serve load than there is actually going to be load to serve. So in the case of, in the case of the GE study, I thought that was a very significant finding in that some forecast of wind generation for the next day was critical to the efficient operation of, of that power market.

So we, recognize now that the wind generation forecasting is going to be critical for growing penetrations of wind, for, for really extracting maximum value from wind generation. There's a bunch of players involved. There's a bunch of motivations that would be driving this. I, I think in the end, though, is that we're just at the stage where we recognize this as a challenge, and there's not been a lot of definitive work done yet. We, we've had some forecasting experiments where we sort of look at how good we can do.

But on the other hand, we've not, in any control area in the country that I'm aware of, really done detailed research on how we would utilize this information. There's anecdotal stories from some control areas in the midwest where, you know, they made wind generation forecasts a requirement per the power purchase agreement. So what they ended up getting was a sheet of paper with 24 numbers on it for the next day. And they found out that that information was not very accurate in, in their view.

And it, it stayed there. So there's this notion that wind generation forecasting doesn't work. We haven't begun to try to understand what we can do with regard to the forecasting accuracy, but maybe more importantly, to try to understand on the operation side how we really leverage that information.

The, the next-day planning is obviously a, an area where wind generation forecasting will be important, but there's potentially other types of forecasts that we haven't gotten around to yet within the day, when we talk about real time power system operations or, you know, maintaining system security. To have an updated forecast of wind generation out for the next few hours, as opposed to relying on information that was generated 40 hours ago, could be of great assistance in, in some context to the power system operators.

We know that generally, as a concept, but we've not made the move forward yet to really explore how this would be done, what its value would be, and then over time how we, how good we, we might be able to get. I'll skip over that.

Fortunately, we do have one project that's starting that I'll mention. This summer, in the state of Minnesota, they're sponsoring a, a fairly aggressive project to really work through the forecasting issue. And the thing I think I'll say here is that what's unique about the project, in my opinion, is that it starts in the utility control room as opposed to on the wind plant side, and that the various customers of the forecast information in the Xcel Minnesota control area will define what they need, how they use it, how it needs to be presented, how it needs to be quantified and, and qualified. And then we would work backwards from there to try to map that to a forecasting system that can develop good information for the operators for a large number of wind plants in the control area.

So in summary, there's been a lot of work trying to assess the wind integration cost impacts on power systems in North America over the last five years, and there's more studies going on all the time. So far, we've found that for the 10, 15 percent kinds of penetrations, these integration costs, however you go about computing them, seem to be modest, $5 per megawatt hour delivered wind energy, or thereabouts. Maybe higher, maybe a little bit lower.

We're also finding, from large wind generation scenarios, that, that almost by definition are going to be diverse, that the geographic diversity seems to move the challenges out to the multi-hour and forward timeframes. We're not so concerned about regulation, fast regulation of AGC or movement within the hour when you're looking at, at large amounts of wind generation spread out over a large area.

It is critical, though, because are utilities in this country control areas, public service, New Mexico is the best example, 1600 megawatt control area. They have the 200 megawatt Taiban Mesa Wind Plant, which is a single wind plant. And furthermore, the, the turbines there are lined, are lined up north to south along the Mesa, so you can get weather conditions that affect ever turbine at almost the same instant. And, and so they're, they're grappling with very serious issues, but they would be on the extreme with regard to the, the present integration experience and what people see happening.

So there's a lot of work to do. Mention a few of the studies that are going on. The Minnesota studies, Colorado. Xcel Energy is, is very active in this area because of the state RPS's, as well as what they see as maybe some, some interesting business propositions with respect to wind energy. Sacramento Municipal Utility District will be starting a project here very shortly, looking at wind integration issues for their control area. Many others, Manitoba, a lot going on in Canada.

There's, there's a lot of activity going on. This is happening as we speak. It's very difficult to keep abreast of what's going on. And so I want to close with talking about the Utility Wind Interest Group just a little bit, in that things are happening so fast with respect to utility, normal utility time constants in the wind generation industry that, that the conventional power industry forums for tracking this kind of stuff, namely, the IEEE power engineering society, are, are really playing catch-up at this moment. And we have a lot of urgent near-term needs.

So UWIG is stepping in to sort of bridge that gap until maybe five years down the road, when there's the appropriate PES technical committees and subcommittees, you know, established to deal with these issues. UWIG provides a forum for really keeping abreast of, of the developments and the studies that are going on. Their biannual meetings, presentations, discussions of results, but maybe more importantly, the, the methods and the data used to do these studies as we see that's maybe as critical as, as the method.

They're established some users' groups to set up smaller groups of folks to work on a narrower segment of issues, and, and work very actively. They're conducted special topic workshops, wind generation forecasting, transmission issues for wind, control area operating issues where they brought in control area operators that are dealing with wind at the present to share experiences.

The UWIG has also provided technical review for projects, which we found to be very important in that they establish essentially a review committee that meets not just at the end of the project, but at critical junctures through the project so that the, the methods and the data, and at the end, the results have significant scrutiny all the way through the process. And at the end of the process you'll have buy-in from a broad set of, of the community.

And I should mention that UWIG will be meeting here in Sacramento in the fall of 2005. I believe Cliff Murley and SMUD will be hosting that meeting.

So my objective this morning was just to give you a, a thumbnail on the forecasting issue and the operations issues. There's obviously more to talk about, and there's -- there'll be more happening in this area. But it, it does portend of some better things to come with regard to wind integration.

Thank you very much.

CHAIRPERSON GEESMAN: Well, thank you very much for your presentation. Your comment about forecast error on the load side and on the, the wind side, the correlation there, or lack thereof, how many studies had you reviewed in, in making that comment?

MR. ZAVADIL: There, there are two broad data points that I used for that. One was a study we conducted for the NSP control area in Minnesota, where we had load forecast information from Xcel Energy, and had developed -- because we were working with synthesized data for the wind scenario there was an extensive sort of forecasting experiment that was part of the project. So one of our subcontractors actually had gone through and done forecasting for each of the days that we were considering.

And it's, you can't say that there's no correlation, but the errors tend to be of a different nature. For example, in load, if you, if you miss your peak you might be low for all the hours during the day. Whereas with the wind generation forecast, you might be plus/minus over that same period. So there's obviously some correlation because of the common meteorology, but --

CHAIRPERSON GEESMAN: Well, let me ask you, if you'd care to speculate, if you expanded that to 20 different studies of different control areas all around the country, do you think you could make a similar conclusion, or would there be simply too much variability to provide you any clear conclusion?

MS. ZAVADIL: I, I would, I would go to your latter comment. Although I, I do believe as we look at this over time we'll probably begin to understand the correlations that do exist between load and, and possibly load forecast error in wind. It's just going to be very specific to the context because the meteorology could be completely different.

CHAIRPERSON GEESMAN: Uh-huh. Thank you.

MR. DYER: Thank you, Bob.

Well, let me continue and, and talk, spend a few minutes talking about the purpose of today's presentation.

We're here today to, as a team, to present the solutions and policy options for integration of renewable resources. Each solution and policy option outlined an action item with it, and, and we're also looking to assign ownership to each of the solutions and follow-up action. The follow-up action would be, would include establishing metrics, taking, tracking progress, research initiatives, performance monitoring. Obtain suggested solutions owners feedback. We're looking for that today. And then obtain stakeholder feedback on solutions, policy options, and suggested actions. So that's where we're hoping to achieve that today.

But let me just step back and just remind the group and the Commissioners as to -- give a summary of the resource development and the characteristics. This state and, and its RPS goals and objectives using the CEC's renewable development report, you can see, just looking at the energy, looking at 2000 through to 2010, we're going from approximately 29,000 gigawatt hours to approximately 57,000 gigawatt hours. The, it's broken into basically two groups. The intermittent group, if you look at the percent of increase from 2002 to 2010, intermittent increases by 207 percent energy.

Looking at the baseload component, we're going from approximately 20,000 gigawatt hours to 30,000 gigawatt hours, which represents an increase of approximately 50 percent. Again, using the CEC reports, this shows a, a likely scenario for new renewable additions by technology and region for the 2010 period. Looking at the capacity, you'll see approximately 7,000 megawatts of additional capacity, most of it made up of, of wind. And you can see that 82 percent of that is, is coming from the southern California area. A lesser amount of geothermal, a smaller amount of bio-mass, and a, a very small portion made up of solar.

Looking at the energy again, it's predominantly coming from the wind, it's coming mostly from southern California. The geothermal mostly projected to be from the Imperial Valley, and, and bio-mass, again, southern California and northern California, a mix. So again, it's just calibrated their significant changes in the, the resource make-up from 2002 to 2004.

As we look at the characteristics of renewable resources, we break them into two groups, the intermittent group, which represents the small hydro,solar and wind. The production may, may not correlate with system load. Production forecast uncertainty. Production variability. Limited ability to control output without curtailments. No regulation or ramping to follow the load requirement.

On the baseload side, representing the bio-mass and geothermal, it's around the clock production; limited ability to control output; no regulation or ramping to, to follow the load requirement.

Let me now walk into looking at our reliability and operational issue list and look at the updated list. When we came here in February we had a list of 11 items. As a result of the feedback that we got from the, the workshop, we've pared it down to nine items, most of -- the other three really are embedded in the remaining nine items.

So now we have load following; minimum load; reserves and ramping; load and generation variability, which Bob just talked a lot about; storage; frequency and voltage requirements; resource deliverability; transmission import capability; and planning and modeling. So we'll be spending some time on these topics as we go forward.

But let me, you probably can't see this very well, I apologize for that. But I, I'm putting this up just to give you an idea of where we're going for the next several minutes. Across the top here you can see these are our nine issues here. By the end of today, we will discuss these ten solutions, and these ten solutions can help solve or mitigate several of these policy issues. And so we'll, we'll be walking through solutions and seeing how it would help mitigate or, or solve some of the issues.

Let me summarize the issues that were analyzed. We were very fortunate, and we really have to thank Dave Hawkins from the California ISO for providing us some recorded data for year 2004, and we used that data to, to do the analysis on these four issues.

And first of all, the assumption that the team used in doing this analysis was that the RP resources would be dispatched first. And we'll talk a little more about that. So to do some analysis, we said okay, how do we get the data, what data is available. And again, the California ISO accommodated our need and they did provide us some, some recorded data for 2004, which represents about 70 percent of the, of the load within the state of California.

But let's talk about the methodology of getting this recorded 2004 data and scaling it up to 2010, and trying to do some analysis with it. First, we started with the recorded hourly California ISO load and renewable production by type for 2004. We scaled the 2004 hourly load by 5.2 percent to forecast 2010 load. And somebody might say that's an awful small number. The reason for that is the, the load for 2004 was significantly higher than forecast. I think it was about six percent over. So rather -- and we wanted to stay with the CEC's forecast of peak demand for the year 2010. So we, we just took 2004, scaled it up by 5.2, and came up with the 2010 load, and it conforms with the CEC's forecast of peak demand.

We then scaled the hourly recorded renewable production by resource type to 2010. We used a ratio of 2010 forecast of energy, divided it by 2004 recorded energy. The renewable resource scaling was based on CEC forecast energy for 2010.

The wind scaled energy forecast adjustment. As we scaled the, the renewable resources up, it wasn't an issue until you came to wind. As we scaled that wind up, due to the newer technology, the different design of it, we found out that we, in some hours we wound up with more energy than there was installed capacity. So what we had to do is clip some energy and move it to other hours. The total amount of energy that we did have to move around was approximately .7 percent. So it was a very small amount of energy, but we did have to move that energy around to stay within the capacity constraints.

The key here is this is the methodology we was used to scale both the load and the resources up to 2010. And then we took the hourly renewable production, subtracted from the load for the purposes of analysis these four issues. And again, that was our assumption is that the RPS resources would be dispatched first, so we could do all our analysis by looking at just the remaining load to be served by non-RPS resources.

Let me just put this one slide up here. And it's kind of a summary slide that looks at the comparison of 2004 and 2010 minimum load and daily swings. And there's a lot of, a lot of information here. On the left-hand side here, you can see the 2004 load swing adjusted for renewables. And then on the right-hand side we have the 2010 load swing adjusted for renewables. So on both the 2004 and 2010, you can see the 365 peak demands for the day and, and the minimum load for each day. So it's kind of interesting. If you look at those minimums, those are significantly lower in 2010 versus 2004.

But the key, four key things jump out at you. Residual minimum loads decrease. You're down here around this 15,000 range. Here, you're up around 19,000 range. The residual peak demand increases. So even though we're installing resources, we still haven't clipped the peaks. There's still an increased peak demand out there. The daily load swing increases, and the volatility increases. You can see, a lot more volatility on, on this one versus this one. And again, this is, this is just 2004 load and resources scaled up to 2010.

So let's go walk our way through the analysis of the different issues, and we'll first start with, with the load following. And again, on, on this slide I'll start in the top left-hand side. And this is the, the renewable production on a hot summer day in 2010, and based on how we scaled it up this would, is maybe a typical profile for the renewables in 2010. We then moved down to the, to the bottom left, and we overlaid a hot summer day over the renewable resources. And you can see, just, just from load alone, the load swing requirement is approximately 22 gigawatts on, on this given day.

Then we move up here on the top right and we have subtracted the renewable resources, leaving us the remaining load to be served by non-RPS. And then we look at the load swing under that scenario with the RPS energy subtracted, and we can see the load swing is now 23.2 gigawatts versus 22. Again, this is just one day.

So what, what we did is to say okay, what does it look like when you look at a whole year of this. And as we look at 2010 remaining load, daily load swings, we find out that it will increase the requirement for controllable generation. Looking at this histogram, if you focus on this red area, circle area, you can see that the, first of all, the white bars are, are 2000 load adjusted for renewables. The red bars are the 2004 loads adjusted for renewables. And you can see that the, the maximum, the 2010 increase over 2004, the maximum increase is 2.2 gigawatts, of which half of that is due to load increases and the remaining half of that, or 1.1 gigawatts, is due to increased renewables. The average is approximately one gigawatt. Six percent of, of that is attributable to load, and approximately 40 percent of that is attributable to, to the renewables.

Again, these numbers could change if you change your renewable resource mix. Again, if you have higher penetration from solar you could maybe mitigate these, these increasing load swings. Again, it, it depends on what resources actually will develop over time. But, but the resource mix, whether it's more penetration or wind or solar or geothermal, will have an impact on these load swing requirements.

SPEAKER: I'm sorry to interrupt. Would you repeat that part? What percentage of these are --

MR. DYER: Yeah. Over here -- right here, on the, on the slide here, it says 2010 increase over 2004. The maximum increase of 2.2 gigawatts, half of that, 50 percent of that, was due to load, and the remaining half was due to increased renewables. It should be in there. Yes. Yeah.

(Note: Questions from the floor.)

MR. DYER: Yeah, okay. I will catch you later.

Okay. So we've, we've looked at the load following, and what we're seeing is as we, as we go forward our load following requirement is going to increase a greater dependency or a need for flexible generation, or controllable generation.

Let's now focus on, on those minimum hours of the day. When you and I are mostly sleeping, the control operator is still managing the system. We're looking at 2004, we're looking at the 0300 hour for, for all those -- all those days in 2004. And you can look at the, at the recorded renewable production on that given hour. Then just below it, we're looking at the same 0300 hour for year 2010, and you can see a significant increase in the, in the production.

So the 2010 production compared to the 2004, the average increased by, by two gigawatts. The maximum increase is 4.5 gigawatts. The minimum increase is 0.6, and production is the greatest in the, in the spring time, in May and June, and it's the least amount in the fall months. Probably no surprise to anyone. We've seen and heard this before.

If, if we look at the residual daily

minimum loads, and what we've done is the, the red line in the background here up on the top represents the residual daily minimum load for 2004. The green line is the residual minimum loads for the year 2010. And, and you can see for just about every day of the year, the, the remaining minimum load to be served by non-RPS resources is significantly lower than 2004. So the 2010 residual minimum load, the average is down by 1.1 gigawatt. The greatest reduction is a 3.0 gigawatts.

Even in the, in the spring time, there's probably a month or so, or two, where the, the load is -- the load for the remaining non-RPS generators is anywhere from three to 4,000 megawatts less than it is in 2004. So if, if the state is struggling with minimum load issues now, and unless we do something different with our resource mix going forward, we are really compounding the problem for the, the system operator. So I think we have some lead time. We have some options we need to think about. And again, we are proposing some solutions.

So load following is increasing. Minimum load, the remaining minimum load for, for non-RPS resources, there's less load there to serve, more of a challenge. Let's look at, at reserves and ramping for a few minutes.

Comparing 2004 and 2010 load ramps, I have the adjustment for renewables. We looked at hour to hour ramps, we looked at three hour to hour ramps, and we looked at six hour to hour ramps. This changes in all of them. 2010 is slightly higher than 2004 in the hour to hour, and the three hour. Not significant, but there are some changes.

First of all, let me just share with you, focus on the, the scale. The hour to hour is plus and minus five, and this is saying that the, on the plus side this is the ramp, an increased ramp, and the minus is a decreased ramp. So this is plus or minus five. On the three hour to three hour ramp, we're looking at plus and minus 15, and on the six hour to six hour ramp we're looking at plus and minus 20.

I don't know. In, in three hours, 10,000 megawatt movement, that's a lot. And, you know, if you can just imagine, hydro moves pretty quick, but the rest of the stuff doesn't move at all. Or, or, you know, typically, a thermal unit is moving at one percent of main plate rating per minute, so it, it's not very fast.

So, and also, if you look at this histogram, you can see the, the 2010 is the red line here, and you can see it's being depressed and it's spreading out in each situation here. And, and again, it's -- so we're compounding the issue here, but it doesn't really start becoming noticeable until you get into the six hour to hour ramp. And so the magnitude and, and volatility of load ramps are higher in 2010.

It's hard to see here. Let me take you to this next slide, and I'm going to focus on the six hour to hour ramp, and I'm just going to hone in and blow up this circled area here, and then give you an example. This first circle here, you'll notice that the ramp ramps up to six gigawatts occur one time in 2004, but they occur 28 times in 2010. If I come down to this circled area here, the ramps up to 12 gigawatts occur 170 times in 2004, and occur 270 times in 2010.

So our, our ramps, again, depending on the resource mix that ultimately comes, if we're staying with the assumption that is forecasted right now, our, our energy ramps as we go forward in 2010, at least for the six hour to hour comparison, they are increasing. And again, it's just something that the, the control area operators are going to have to manage. And we need to figure out ways to help them manage and get the right solutions in place.

Let's shift and talk a little bit about reserves. We'll first talk about what does the WECC want from the control area operator in California and in the other western states.

First of all, as we all are aware of, the purpose of the operating reserves is really to help the operator manage the uncertainty and the contingencies that are going to occur, because they do occur. They occur every, at every day. It just wouldn't be life if the operator had came in there and everything was perfect. So there will be uncertainty, there will be contingencies they need to manage, and that's the purpose of the reserves.

What the WECC is expecting each and every system operator throughout the, the 30-some odd control areas in the WECC, is don't just come up with a reserve planning in the day ahead or once a day or twice a day. It's an ongoing. The operating reserve shall be calculated such that the amount available can be fully activated in the next ten minutes is known at all times. So as all these variables are changing, the operator needs to know how much reserve do I have, how much reserve do I need, and how much of it can be deployed in ten minutes. He can have a lot of reserve. It's can you deploy it in the time requirements that, that's the key element here.

How much does the, does the control area operator need. Equal to the total of the regulation as known by the, this red area. The non-firm imports, the on-demand requirements, such that if you have a contractual obligation with another organization they can call upon you for energy and capacity, you have to have reserve to cover that. And then the greater of the single largest contingency or the sum of five and seven percent of the actual load requirement. So that is your, your operating reserve requirement, and it must be, the operator must be aware of that on an ongoing basis and it must be deployable in a ten-minute period. Managing operating reserve in real time.

So as all these variables are changing,

the operator looking at his, his hourly regulation requirements will require the control area operator to continuously adjust the operating reserves. So if you're in this morning pick-up when you're picking up two, three, four, five, 6,000 megawatts an hour, you might start with 10,000 megawatts of reserve, but by the end of the hour you don't have 10,000 megawatts because you got 6,000 megawatts for the load pick-up.

So again, it's constantly adjusting when do I need to bring in more, what's, what's in the pipeline, can it meet the time requirements and such. So as, as things are occurring on the system, they're constantly adjusting.

Forecast errors, whether it be on the load side or the resource side, will require the control area operator again to continuously adjust the operating reserves either up or down.

Contingencies. Forced outages of either lines of generation will, will require the control area operator to replace these operating reserves. So, one, we have them in there just for these types of situations. Events occur, they will deploy their operating reserves, but then they're obligated to replace those reserves within a 60 minute timeframe.

Let's look at how does, how does the control area operator, or how, you know, what are the options for integrating intermittent resources and the impacts on operating reserve. Treatment of energy and capacity from intermittent resources in the day-ahead and hour-ahead plan.

You know, one, one option is you can just include full nameplate rating output in your, in your resource plan. That's pretty risky. There's a high probability that you're going to be wrong, and you're always going to be scrambling, you're always going to be behind the eight-ball, you're not going to have enough operating reserve.

The second option is include forecast hourly output in the plan. And there's some variability around the forecast, you're either going to be plus or minus.

The third option is include zero output in the plan. You're over-committing resources in the operating reserve, there's no reliability issue. Option one is probably not a very safe one to go down. We, we need to focus on option two. It's clearly the most reasonable and logical one to go after. The question is, and as Bob was sharing with us, the volatility around forecasts. If you don't have confidence, you're not going there. So you have to have confidence, you have to achieve the maximum efficiency with these types of employment of these resources, and to be reliable you need to have confidence in what's going to happen.

The third option, you say well, why would you do that? A lot of people do it. That, that's the more norm. It's not unusual for, due to lack of confidence, that the control operators count no capacity value, and so you're always on the plus side. It's the safe side. I, I think we, as a state, need to focus on option two and, and focus on how do we enhance our ability to forecast both load and resource, renewable resources.

You know, a strategy for managing operating reserve with the accelerated RPS would be, one, to immediately start monitoring and tracking forecasts of actual performance for all intermittent resources. And one, doing that in a consistent standardized method and metric. You know, it's like a lot of things. People track things, but everyone's doing it different and you can't come back and compare things. Again, one, doing the constant standardized method, do that at several levels. Find out who's the best forecaster, is the developer, the region, the load-serving entity, or the control area operator, and then do it in several time windows. Look at, you know, the day ahead, 12 hours ahead, six hours ahead. Where are we getting the best information by the best individual, and how do you -- and I think this really leads you to, it's one thing to do things day-ahead, but there's a lot of value in, in moving the forecasting closer and closer in time. We get better and better and there's less variability when we do that. And I think that's really what Bob is kind of telling us, as well.

Develop the best available metering to support the better forecast. Perform benchmarking studies to identify best in class for forecast models, processes and techniques. Assure that the portion of the load serving entity and the control area operator resource portfolio that is used to provide operating reserves has the necessary attributes. Is it quick start, is it fast ramping, and will it cycle.

I'm not going to move to load and

generation variability, and I think, you know, I, this is probably not a whole lot different from what Bob was telling us. And, and first of all,we just looked at daily chronological change in renewable production at the time of peak. And we looked, compared 2004, which are the red dots, and the 2010, which are the, are the green dots. And, and you can see, you know, the 2004 is just a nice, tight cluster right around plus or minus little bit from zero.

And, and the scale on the left is -- excuse me -- plus or minus eight gigawatts. And you see, as we took the 2004 resource production and scaled it up to 2010, there's a fair amount of, of variability. So 2010, the variability of renewable energy production is higher than 2004. Probably not rocket science, no surprises there.

The state of the art wind forecasting techniques and monitoring systems need to be investigated and employed to ensure successful integration of accelerated RPS generation.

Again, looking at 2004 versus -- looking at the chronological change in weekday residual load, what we first did here is say hey, let's just throw out all the weekends and all the holidays so we don't distort this, this chart. Again, this chart is, is plus and minus. A plus eight gigawatts and, and minus ten gigawatts. So plus means that the load was greater than the previous day. Minus means the load was less than the previous day.

And you can see there was a lot of variability in 2004, and there's a lot of variability, and even more variability in 2010. So the change in the residual peak demand increases, load and renewable resource volatility will increase, presenting significant challenges for the control area to manage. And, and I think, as Bob was saying, is, you know, in a lot of cases some of this will cancel out. But in not all the cases. So, you know, if you look at some of these outlies here, you know, you've got a 6,000 here or 8,000 here, you know, if you compound a significant forecast there on the load side and add it to the resource side, that's a challenge.

So it, it's really up to us to, to understand that, given the tools, the techniques, the processes to mitigate those variability on the load side and on the renewable resource side.

So let me just kind of recap what we've

said, and this is that same slide you saw earlier comparing the 2004 and 2010. The, the key elements there is that daily load swing increases, residual minimum load decreases, residual peak demand increases, and volatility and uncertainty increases.

Let me now talk about some of the solutions, and we'll first talk about Solution A. And let me just walk you through this template here.

What we have here, this is Solution A, it's establishing requirements for controllable generation. And this template here is, here's, up on the top, here are nine issues. Over here on the left in yellow is the solution as, as we take the necessary actions. This is the issues that it is intended to solve or mitigate.

So in each case we're putting out a solution. We're identifying some action requirements, we're identifying an owner, identifying some potential research, and any potential metrics that could be used for purposes of modeling and tracking our performance in achieving these goals and objectives.

So in this case, we're saying let's

establish requirements for controllable generation. You know, let's first find out what is it we need. Establish attributes requirements for the current controllable generation. The control area operator needs to figure out what they need now. As we go forward the control area operator and the CEC, maybe in the form of some research, need to forecast what are the, are the attributes, controllable attributes that we need in 2010. And from that, define the metrics as a result of, of that forecast, then monitor and track our requirements. Acquire sufficient generation with the necessary attributes to meet AGC and load following requirements in the procurement process.

And that's, the owner of that is the load-serving entity. And they need to procure them and, and pass them on to the control area operator for implementation. So this is an example of, of our Solution A.

Solution B is enabling load to participate in real-time dispatch. Again, if you're looking for a solution to minimum load problems, you, you set up the necessary markets, the settlement process, the standards. What are the attributes you want load to, to bring to the table, what are the standards associated with that attribute. Define them, give visibility, identify what the requirement might be. Set up the necessary markets for that. And then just start tracking our progress moving down that direction. And, and then put the necessary infrastructure in to enable load participation and automatic load dispatch.

Looking at C. Renegotiate existing contracts for additional dispatchability and minimum load. You know, as we said early on, a lot of our issues are based on the current resource mix that we have. You know, we have a lot of nuclear, QF, CDWR contracts, coal in this stat, and so we need to look at if we're going to need more dispatchability and flexible generation, how do we get it. What do we do with our existing portfolio from now to 2010 to get that additional flexibility and dispatchability.

So here's, here's some suggested actions. Here's some owners, and here's some metrics. Moving to Solution D, modify the California ISO AGC algorithm, if you're going to integrate load for dispatch and help you solve the problem, you need a way to do it, and, and the ISO needs to modify their algorithm. Also, there's a lot of flexibility or enhanced load following and regulation that they can achieve right now by modifying their AGC to better optimize and somewhat conform to hydro schedules and not violate them.

In other words, I think load-serving entities would turn over their resources for AGC if they felt that they would, they would be better optimized, and, and not use all their water up in a short period of time.

Solution E is modify WECC and California ISO interchange scheduling protocol, policies and procedures. And again, it's just a whole shopping list of things that, of actions, you know, modifying protocols. You know, how do you, if we're challenging ourselves for load following and ramping, maybe we need to have the ramps longer. Well, right now we, we move large blocks of energy across a 20-minute window across the hour. Maybe we need to do a 30-minute window, or a 40-minute window. We need to figure out what it is we need, and work with the appropriate control area operators and WECC to, to implement those procedures.

Is there a need for dynamic scheduling, and, and what process of the procedures and protocol need to be implemented to, to get dynamic scheduling into this thing.

Solution G, actively manage generation output which exceeds planned levels or when total generation exceeds load. You know, we struggle with minimum load now. We said the load available for non-RPS resources is going to be three to 4,000 megawatts less in the future. How are we going to manage it. So here's a shopping list of, of some action items, some owners, some research, and some metrics that we could go after to, to help manage that situation here.

And again, this is just a continuation of, of Solution G.

CHAIRPERSON GEESMAN: Jim, I think you skipped over F.

MR. DYER: F is in another second. I'll --

CHAIRPERSON GEESMAN: Okay.

MR. DYER: That's, it was just a duplicate. I apologize for that, Commissioner.

Solution J is improve production

forecasting. And, and again, again I'm just reiterating what Bob was saying, we need to investigate the best practices of wind energy forecasting and implement the state of the art forecasting tools. Continue efforts to improve wind monitoring and data gathering. Evaluate changes in the California ISO protocol to allow later forecasts of intermittent energy in the daily plan.

So that was some of the solutions that we're recommending for the first four issues. I'll just spend a few minutes on the, on the remaining issues, being storage, frequency of voltage requirements, resource deliverability, transmission import capability, planning and modeling.

And these, these five issues, five through nine, involve data, technical evaluation and modeling that is specific to utilities and control areas, and, and we didn't feel it was appropriate for us to, to get into areas of their expertise and try to make some assumptions. Only those individuals can make those correct assessments. So though we did not do any analysis, the project team did make some observations as to what needs to be done in this area, based on experience and, and talking with some of the, the individuals.

The, the first one is Solution G, actively manage generation output which exceeds planned load. Again, it's, the action requirement is develop the statewide strategy for managing, making efficient use of existing pumps. We have over 4,000 megawatts of pump storage. Is it coordinated, integrated? Can we use any of that pump storage to help mitigate some of the minimum load problems, or help with intermittent resources to firm it up, or anything else. So, you know, there was some talk at the last workshop of do we need storage. Well, we've got a lot of storage but it's not coordinated and not maximized.

And then determine the need for additional storage. I think there's an opportunity for research. You know, if you're going beyond the 20 percent to 30 or 35 percent, do we need storage, and at what point.

Looking at Solution F -- Commissioner, there's your Solution F -- ensure adequate generation performance standards are in place with clarity of implementation to ensure system reliability. And again, it's, one is, the first one is looking at the frequency side of it. You know, the WECC has developed a low voltage ride-through standard. The question is, from a council perspective, the entire WECC, do we need to look at frequency performance, frequency ride-through or frequency response.

So the WECC has set up a, a special wind task force that will be looking at, at some of these. There's one there looking at the low voltage ride-through, you know, what's the next step for that, and then also looking at is there a need for any frequency standards. The second bullet there just talks about as we roll out the standards for low voltage ride-through we just need to monitor and track the control area's performance in that area.

Solution H, improve transmission studies. Transmission owners and the WECC, we basically studied worst case situation or, or peak demands. And so we don't spend a lot of time looking at the non-peak time periods of the year, the winter months, the spring, spring months, when in some cases if, if you're only looking at the peak and if you're looking at intermittent --

integrating intermittent resources, when you're looking at that timeframe you're not seeing a lot of production. You're not going to see problems. It's not until you implement, operationalize the resources and they're in maximum production in the middle of the night, in the middle of spring, that something pops, and you find all the weak links in the fuses in the system.

So we need to develop off peak cases so that different transmission owners, control area operators and, and different WECC organizations can better study it. Look at, you know, what, what is the impact on transfer capability if the WECC implements 30,000 megawatts of renewable resources over the next 15 years. You know, the response of, of some renewable resources, the frequency response is not overly impressive. If, and that is one key element of, in transmission rating.

So we don't want to lose the transfer capability we have right now, so let's get the WECC to look at some of these cases, do some what if scenarios if we have 30,000 megawatts of renewables, look at it. And it may not be a problem during the peak time when you've got

150,000 megawatts of -- generation to the grid, but it may be a problem in, in the non-summer months in the middle of the night. We may be losing transfer capability in our non-summer months.

Again, this is, we just need to look differently at, at transmission studies and how we view them. And going along with the transmission studies, we need to have improved modeling, assure all necessary data and information required for simulating the power flow studies is available. Develop the necessary monitoring devices and infrastructure to acquire meteorological data.

So I think, you know, talking to the planners, they're frustrated. The models don't have the appropriate data and information to model those systems correctly, and the meteorological data, having that type of information would support their, their modeling capability.

Okay. Coming back to this, this one slide again, which is summarizing the solutions and policy options. Again, we, we have provided ten different solutions. They're going, each, each solution is addressing at least two or more of, of the issues that we've identified. And again, we're going to be looking for your feedback and your comments and reaction to that.

Let's look at, very briefly, look at the solution priorities. I think what some of the high priority policy options, one is to define the resource attributes that we need. Define what we need, develop the appropriate metrics and monitor the performance for the flexible type of generation that we need to support integrating renewable resources.

Reduce uncertainty. Reduce scheduling lead times; improve data availability; improve metering, monitoring and forecasting techniques.

Reduce uncertainty. Reduce scheduling lead times, improve data availability, improve metering, monitoring and forecasting techniques.

Resource policies. Appropriate resource mix. You know, who, who needs to define that. Dispatch priority for both internal and imported resources. And that's kind of -- could be a little sticky one, because now you're, you're encroaching on the FERC policy there. But again, it needs to be addressed. Load participation, coordinated use of available storage.

Improving planning and modeling. We

need to resource deliverability, look at, look at the resource deliverability. Import capability, improve the models, perform off system contingency analysis, and again, coordinate with our other WECC member states.

That fairly well concludes my portion of the presentation. I, I'd now like to move to the panel members and I'd like to ask the different panel members to come up, please.

Commissioner, do you want to take a break, or --

CHAIRPERSON GEESMAN: No. Commissioner Boyd and I have an obligation at 12:00 o'clock, so I think we ought to just push through.

MR. DYER: Okay. What we have, I appreciate the, the panel for participating, and what I'm going to ask that each of the panel members to do is to look at the first three questions, which basically address the solutions, and, and provide the Commission and the other stakeholders in the audience their reaction to them. So I'll ask each of the panel members to do that. And then I'll, I'll come back and ask you to react to the last three, which basically is on the implementation side of, of the solutions.

So, Jan, can I get you to start with it, please?

MR. STRACK: I'm Jan Strack, from San Diego Gas and Electric.

Jim, I hope I don't stray too much from your format here. I'm just going to make some general observations.

First of all, I think the report's helpful. I think it highlights for everybody that the world's going to be different, you know, five years from now, based on the deployment of our expected levels of renewables, and I think it's very helpful to get that out on the table so people can start thinking about what they need to do to be prepared for that.

I suppose the one overriding concern that I did have looking at the report in the suggested solutions was the sort of notion that we're going to build in a requirement for the load-serving entities to add resources with a certain specific, fairly rigid set of requirements. And mainly I'm, I'm looking at the regulation area, some of the -- perhaps the operating reserve requirements.

And what I'd like to suggest as sort of

an alternative is, is more that we provide the information, as it's done in this report, and then actually allow the load-serving entities to take that into account when they actually begin to devise and build out their resource portfolios.

So, for example, one would expect that over the next five years, if, if wind, for example, materializes at the rate we're currently thinking, there's going to be a high demand for resources that are -- have a fairly high degree of controllability. What that says to me is that prices, for, for example regulation, regulation down during off peak periods, are going to be up. And what that, what that would then say is that both the load-serving entities and prospectively merchant developers of generation, even, start thinking in terms of building resources that have those kind of attributes. But, but basically, to allow the load-serving entities then to roll, roll that into their procurement thinking as they see best for their customers, rather than to actually mandate a specific level of, of certain attributes that they have to have in their portfolios.

So I guess that would be my overall comment and concern, that we not make this too rigid and allow the load-serving entities to actually meet those requirements as they see best, given the information that, the useful information that's being provided here.

One other thing I, I would add is, is I thought it was pretty interesting on the minimum load side that you're actually going to be seeing some lower minimum loads than you have in, we have recently. I think that what we ought to be doing here is focusing on prices during those low load hours, because my suspicion is that if we actually let the prices drop to the levels that reflected the value of energy during those difficult operational periods, probably into the negative price range, you would very quickly see responses that would largely eliminate this problem on an economic basis.

So rather than, again, sort of overlay this with sort of a heavy-handed here's the kinds of things we need, or kinds of technologies we need to fix the problem, in a lot of ways I think the prices themselves, if we allow them to drop to the levels that are reflective of the conditions, it'll be a self-correcting problem in large measure.

MR. DYER: Okay. Thank you, Jan.

Can we go with Dave Hawkins.

MR. HAWKINS: Well, first of all, I'd like to say congratulations on a very complete report, very thorough. I think you really covered a lot of interesting issues, and really laid out a framework to start to attack many of these problems. So I appreciate the framework.

In terms of overall completeness, I think you, most of it is there. The only thing I would add is in terms as, as we build out the portfolio of the types of generation requirements, the one thing that we were going to add to the list is the need for black start requirements. So we're deficient in black start in some areas, so we would add that to the mix.

The other thing is, as we're looking at, coming back to the issue about the minimum load at night, the big issue I think for us is going to be having thermal type units that are -- are capable of cycling off reasonably well at night, and getting started the next morning to go into the morning load pick-up period.

Certainly the combined cycle combustion turbine plants today really hate to go off at night. It increases their maintenance issues, their start times. They lock up for five to six hours automatically when you take the unit down, so having the ability to start, having units that you can cycle a lot easier without the corresponding problems is going to be, I think, one of the big issues in the future. And particularly, even though, you know, the price goes negative at night and we're trying to give away the energy, especially during the May-June time periods, the rest of the industry also has problems. Maybe we're fortunate this year that the northwest really needs our energy, because we've been exporting a lot at night up to the northwest.

But typically, it's going to become more of a problem throughout the whole western interconnection, particularly if New Mexico and Nevada really start to ramp up wind generation resources also, and if their profile of energy profile matches California then we really, really will have a region-wide problem, not just a California problem.

So I think we have to look at all that resource mix. I think the priorities in this thing are right. What we need to do, though, is to make sure that we include all the transmission constraints and deliverability. And I think also we need to start looking at doing the generation planning picture, particularly on a month to month basis, and looking at the fact that the May/June period, as you correctly identified in here, has some very unique characteristics because that's when the hydro, the water's coming down the hill, the hydro's running hard, and that's also the time that we have maximum wind generation production. It certainly is an ideal time to have the nukes off for refueling.

And so the whole management of the portfolio of generation during these different months is something that we really need to start taking into account and looking at ways of using the tools for doing the planning on month to month basis for what the right resource mix should be.

And finally, I think, you know, the issues that you've pointed out about pump storage and the whole concept of looking at some new strategies, new rules for how to do the mix correctly, or the most optimal way of putting the mix of resources together to keep the costs as low as possible for the consumers, is really the direction that we need to go. So again, thinking about new tools, research, and to coming up with better optimization tools, and maybe new strategies or rules and working with PG&E and Edison on how to best manage some of those pump storage facilities, and including, I think, Department of Water Resources. All this whole concept about what we can do with pumping loads, both as interruptible loads and as energy storage devices is, I think, a whole new area that we need to look at.

So as I've gone through the report I've marked up lots of different things I'd like to add to the, you know, individual areas. But essentially, I think you've really covered the waterfront quite well. The only other thing I would add is on frequency response requirements, there are things we need to do to make sure we've got the right frequency response.

And, let's see, I had one more thing. Also, on limiting ramps, which you were talking about, is I think the direction that we'll probably try to go in the future is not go for 40 minute ramps, but do a cap on import ramps and the

20 minute period. So instead of saying any ramp will do, we may limit the ramp to, you know, 1200 megawatts, or something, for imports, and then have to do several ramps during a, a hourly period. And that, again, would help to reduce some of the volatility and the need for a large amount of load following just to, to re-shape the energy delivery to meet what the load is doing.

So I think there's a variety of approaches and stuff that we can, we'd be glad to look at.

CHAIRPERSON GEESMAN: Two quick questions. One, what type of thermal resources do you see in the future better fitting that cycling duty cycle, and, two, how much should we be concerned, if you assume the Tehachapi wind resource is the large incremental gain in the next five years, how much should we be concerned that much of this integration is all going to have to be done within one utility service area?

MR. HAWKINS: Well, the answer to the first question, the type of units that can cycle, I think that's something we need to work with the GEs and the Calpines and Dukes, and others, to see what else can be done. There are occasions where they have taken their combined cycle plants and they have done things to modify the plants so they do have much faster start times.

In one case it was accidental, and during the start-up period they sort of shaved the ends of the blades a little bit, accidentally. But that does give them a, a much faster start time, so they can start in about an hour and a half, because they don't have quite the, the thermal constraints that the other ones do.

The other concept that has been talked about is even after you shut down the unit, if you use a residual heating effect, basically an electric blanket, around the turbines, you can keep the turbine housing hot enough that the start time then on the units can be reduced. So there are probably engineering things that can be done to both modify some existing units, and potentially they design new units that have a little bit more flexibility, maybe not quite as close a tolerance on the thermal expansion of he units. So those are some possibilities.

COMMISSIONER BOYD: Before you go on to Commissioner Geesman's other question, I was going to ask you a third question in terms -- it is basically an adjunct to question one, and that was the cycling of combined cycle plants.

I brought back some material from a meeting I was at last week that really wasn't on this subject at all, but that, you talk about new tools, that I read this to be some kind of new technology to help with the very issue you mentioned, that there are new technologies out there that some people have that will reduce, if not eliminate, depending on how zealous the vendor is, this problem with cycling of combined cycle.

So just add that as a footnote. I've turned that material over to our staff and see what more there is of it.

MR. HAWKINS: Excellent, thank you. Look forward to all, any information we can get. And, and the response we've gotten from working with the different owners of the combined cycle plants that they're more than willing to work with us on changing the characteristics of new plants in the future, and their procurement, if we will just specify what we want, and put that out there, and then encourage, you know, Edison and PG&E and, and San Diego to modify the portfolio of their procurement to include some of these other types of characteristics. So I think the feeling I get from the industry is certainly one of cooperation if we put the specificity out of what we really need.

Coming back to your other question about the deliverability out of Tehachapi, it certainly is an ongoing discussion as to how to shape the resource, resources that can -- for deliverability of that energy throughout our major load centers in the state. And the question is, you know, what is the right transmission upgrades that require that and how much do we have to go back to re-shape some of the energy delivery schedules.

And Jeff Miller and I talked about this issue some. We're looking at new products. They're using a product now called Grid View, which allows a lot of flexibility in creating the models for these programs, and we're looking to see how far we can go with studies and modeling of that to come out with some better answers.

CHAIRPERSON GEESMAN: Thank you.

MR. DYER: Thank you, Dave.

Jorge Chacon, from Southern California Edison.

MR. CHACON: Hi, good morning. I think

a couple of, of things that, that kind of stood out to me is, you know, the difference of results from Caldwell's presentation, you know, where there seemed to be no impact, and the presentation that CERTS provided. And I think the rationale, or the reason behind that is centered around the topology, the fact that the Tehachapi area is, is one geographic piece of property and as a result, you know, as opposed to Germany, where you have distribution throughout the whole nation, presumably a larger piece of geographic real estate, you have some of the diversity issues that are not amplified in the Tehachapi area because of the smaller geographic region.

And that is a concern. I mean, you know, it is something that as part of the collaborative study, we, we -- you know, talking about we're doing more studies to figure out what the best transmission alternative is to assist with the deliverability with integrating such a large amount of, you know, wind generation in Tehachapi.

For the most part, I think as far as the solutions are concerned, you know, I, I look at it and I think there's one missing, and I think that deals with the, the renewable resource portfolio standards itself requires 20 percent renewable resource but doesn't specify what amount corresponds to solar, you know, geothermal, wind. And it does look at the least cost best fit. So I think we need to somehow focus into how do you define what the best fit is. You know, there may be a threshold by which you cannot exceed because operational issues surrounding the, you know, how you get the power out. And, and I don't know that we have a firm understanding as to what that best fit amount of generation will look like. So I think maybe some, some thought into how we shape this RPS and, and you know, what we do with it.

As far as the rest of the solutions, I think they're on, I think the solution G talks about the curtailment, or I, I interpret that as a curtailment of generation. And if we're talking about curtailing these RPS contracts, I mean, we have been having problems as far as, you know, they're all take, you know, take or pay contracts, so how do you curtail a take or pay contract? And then there may be some issues surrounding with that.

And as far as transmission studies are

concerned, as part of the system impact studies we do perform heavy summer studies, we do perform off peak studies. We do perform the studies that we believe are necessary given the area that the generator is inter-connecting to look at different operating conditions. So while the solution is appropriate, I think it needs to be emphasized that we already currently do that.

That pretty much sums up the, the issues or the comments I have.

MR. DYER: Okay. Thank you, Jorge.

Chifong Thomas, from PG&E.

MS. THOMAS: First off, it is a very complete report, and it's, it is give us a lot of information to go by, and, and it's very good.

As far as the question on whether there's agreement doing the suggested research and metric for monitoring performance, we agree with the suggest research metrics. And furthermore, I think the utilities would need to participate actively in the, developing the solutions and the, and the process.

And then there's also a question on, on the suggested action items for state agencies. And we believe that coordination between the municipal utilities, the PUC and the CEC and ISO, would be required to come up with a good solution to overall problem.

As far as the solutions are concerned, they talk about developing actual requirements, and I agree with both George and Dave, and also Jim, that it is probably easier for, from our standpoint, that to, to put the requirement into the best fit as when the utilities are selecting their mixture of resources, because that way you, you, instead of having to work around, we basically it's more straightforward to select the, the group of resources that would cause the least problem to start with. And, and also that a contract with the incentive would also be a good idea.

The other thing, too, is that in, to put this in the, in the best fit also give you another advantage, is that resources today could be intermittent and could be uncontrollable, but because of the best fit requirement that technology might develop to allow it to become more, a better resource for the, for the consumers.

As far as storage is concerned, there's

two, two requirements that need to be looked at for use of existing storage. The first is that there should be no, there cannot be any congestion on transmission to go from the intermittent resource to the storage, because -- at the time it's being used. And secondly, when the storage is going to be for the, for the resource to be used, there shouldn't be any transmission congestion at the time it had to be used between the storage and the load center.

So, of course, timing is important. And it's also important to take a look at the impact on how this mix would, would impact the operation of the storage unit. As far as the priority is concerned, I think the priorities is about right. And, and yes, I agree with, with Jorge that we already do studies for inter-connection studies based on both peak and off peak, and any other situation where we would have concerns.

For example, sometimes the concern may not be off peak, it may be partial peak, depending on really the location of the resource and how we want to integrate it. In fact, there was a -- why the peak is, for example, in PG&E the peak is not, may not be really where the problem is. It could be that it just passed the peak in the shoulders, because when you just pass the peak the likely scenario is the ISO will start cutting back on the most expensive resources which would happen to be the oil and gas at the, at the load centers. And then you would, because of that you would generate a higher power flow from the cheaper resources, which is normally hydro, into the load center. So, so therefore, what we really need to look at is more than just a peak and off peak, and any other reasonably adverse conditions.

WECC is also be looking at, will be looking at frequency response and voltage and modeling. Modeling is certainly an issue, because how detailed model should you have for the generator. The wind farms are, are diverse, so obviously modeling each generator would be too much for the program to handle. And yet modeling too little might give you resource that may not match reality, so that is something that we'll be looking at.

Thank you.

CHAIRPERSON GEESMAN: You know, both you and Jorge, Chifong, raised the least cost best fit issue. The current RPS places that decisionmaking exclusively in the hands of the utilities, and I suspect because of the relative low cost of the wind resource, the utilities have indicated a pretty strong desire in their renewable portfolios to, to purchase a fair amount of wind. It strikes me that if you assume that cost differential continues into the future, which is the way our staff has, had made the assessment, there will be a continued disproportionate emphasis on wind in the renewable portfolios that each of the companies consider to be least cost, best fit, and that compels the rest of us, and I know the two of you don't sit on your procurement group, that compels the rest of us to figure out how to do these work arounds, and also to figure out how to pay for them. And I think, finally, to rationalize that the expenditure is worthwhile.

Jorge?

MR. CHACON: In this first go-around of the RPS solicitation, because it is early in the process, though we are concerned with the issues, you know, long term as more and more wind developers generation develops, we believe that initially, you know, in this first go-around it's not as problematic. I mean, we've already got, you know, what, 900 megawatts on the state, somewhere around that neighborhood. And, you know, we didn't sign up a whole heck of a lot of wind.

So, you know, it would be a concern if I were looking at, you know, Edison were considering signing up the entire 4,000 megawatts in Tehachapi. We obviously are extremely concerned with that scenario, so as time progresses forward, we will be looking at the best fit in more scrutiny, and we will be assessing whether, in fact, it's because of the relative cost does it even apply. I mean, if you can't get it in, you can't deliver it, it becomes a non-considerable renewable resource. You go with the next least cost renewable generation.

MS. THOMAS: I agree with Jorge that that is a concern. As planners, we have to look out into the future, and certainly we don't want to have the operators curse us when something happens that we have not foreseen. And this is now becoming more and more a concern exactly because of the fact that we are seeing more wind technology because of the cost. And so then, yes, best fit would have to come in a lot more later on to select the right group of resources so that we can operate.

MR. DYER: Okay. Thank you, Chifong.

Cliff Murley, from the Sacramento Municipal Utility District.

MR. MURLEY: My comments are directed at the wind energy aspect of this report, rather than the other renewables.

The list of issues included in our report is an important and relevant one that should be rigorously analyzed. Let me just give you a little bit of background about SMUD's wind integration plans.

We have a renewables goal of 23 percent by 2011, including three percent for our green pricing program, Greenergy. We've issued an RFO, received dozens of proposals, and have found that wind resources are generally the most available and least expensive, a result that disappoints our schedulers and operators more than a little. We have a current and real need to gain a much better understanding of the implications of adding a lot of wind onto our system, both operationally and financially.

A few areas in which SMUD is supportive

of wind related R&D efforts include continued Commission work on improving wind forecasting accuracies, development of a statewide wind forecasting infrastructure beyond that in the CAISO program. We'd like to see some efforts to gain a better understanding of wind plants' responses to frequency and voltage related system events. We don't have much experience in that. And we'd like to see an effort aimed at gaining a better understanding of the potential need for and benefits of utility scale energy storage, assuming that thousands of megawatts of wind are going to be added and that we are increasingly faced with minimum load issues and problems.

I have a few observations from this report. The analytical work done isn't transparent enough for us to understand what assumptions were used in all cases and what analytical methods were used, as well. I mean, what are the development scenarios for each of the various renewables, both in megawatts and locations. That just, that information wasn't included. What is, what is their share of ramping and load following needs between wind and the others. That isn't apparent, either.

It does appear, from reading the report, that wind was simply scaled up from 2004 to 2010, assuming more wind in each of the assumed four to five sites in California -- I can only guess at that-- and that 2004 hourly profiles would be simply be scaled up as well. If this is the case, the report neglects the twin benefits of lower wind plant variability due to increased plant size. And it neglects the lower variability due to the development of wind plants at locations other than the four to five assumed sites in the plan. It also therefore means that the determination of ramping and load swing requirements is likely incorrect, and that the description of the future minimum load situation is as well, to some degree.

After reviewing the methods and results of the wind integration studies done for Xcel Energy and in -- this work seems surprisingly disconnected inasmuch as the methods developed at Oakridge National Laboratories, Laboratory, and National Renewable Energy Laboratory to develop operational impacts don't seem to be used in this report. Or it isn't apparent that they were being used.

We at SMUD need a more robust and convincing analytical study to fully address all issues and concerns we have about integrating lots of intermittent renewables if we expect to persuade our decision-makers to make those commitments. The good news is that with Commission co-funding, SMUD is about to embark on our own detailed wind integration study similar to the studies done for other control area operators, to examine some of the following major issues.

We're going to investigate the operational and financial impacts of integrating large amounts of wind onto our system. Determining the future need for regulation and load following generation and their costs. We'd like to evaluate the impacts of improved wind forecasting and wind forecasting in general on needed reserves. We'd like to really take a close look at system operation at minimum load, and start to consider strategies including curtailment of wind as appropriate during those times. We'd like to, and we plan to analyze the impacts of additional pump storage, such as a project we are planning in the upper American River project hydro-system.

Very importantly, we are emphasizing training development for our operators and schedulers so they can manage large amounts of wind. We're interested in developing the ability to reduce lead times for scheduling wind in, in our control operations area. We plan to model an expanded SMUD-owned Solano wind project, as well as the addition of one or more other wind projects located throughout California and Oregon. We believe the geographical diversity of wind is going to mitigate the variability intermittency and lower overall costs for us, as well.

I might recommend that the state of California consider a similar statewide integrated assessment of the operational reliability and financial impacts of the state's RPS scenarios, both 20 percent by 2010 and 30-plus percent by 2020. The range of scenarios could include a progression of renewable penetrations by region within the state, and include some of the same components as have been included in other wind integration studies in the U.S. in the one planned for SMUD.

The capabilities to conduct this type of study are available. They exist, and they're available. I'd expect that a fully collaborative process to scope this type of project and to evaluate the results would take us quite a bit further to reaching our renewable goals. Thank you.

MR. DYER: Thank you, Cliff. Let me -- oh, excuse me. Go to the next series of questions, questions four, five, and six, really address the implementation of, of the solutions and action items. And Jan, could I ask you for your reaction to those questions, please?

MR. STRACK: Well, I, I guess I would just sort of repeat my first observation, which I think more or less has been supported by the other panel members, which was that as part of the, sort of this best fit approach, that the load-serving entities, you know, have the flexibility to accommodate as best they see fit for their customers these, these requirements, as you've characterized it in the report. But if you, if you allow that kind of flexibility, I think that's certainly useful.

One other implementation point that I'd sort of highlight, and again it's been mentioned here, including by Mr. Geesman, which is the, the sort of ruthless approach to eradicating every ounce of congestion whenever and wherever you see it, I think is a mistake. We believe that's the wrong sort of focus. I think Mr. Hawkins' mention of the grid view planning model I think is a useful tool to sort of get our, get our hands on what congestion's worth getting rid of. Because, you know, we, we sort of get fixated with this identify every ounce of congestion and, and kill it. But I don't think that's the right sort of focus, it certainly isn't consistent with the least cost best fit world, and I just would like to emphasize that may be a good implementation tool that, that we ought to continue to pursue.

MR. DYER: Thank you, Jan.

Dave, any comments on the implementation?

MR. HAWKINS: Thank you. We've, one of the steps that we had been planning to do even before this workshop is putting together a working group to address some of the operational issues. And we've, you know, talked internally. We have Randy Abernathy's support for doing that, and this goes beyond just the participation and the PIRP program, but really all the wind generators and renewables to be able to bring them together and talk about some of the, our observations and data and what could be, you know, what is going on with the different renewables during these periods, and what we could do to mitigate some of the problems.

And both Mark Smith and Hal Romanowitz have iterated in front of FERC as well, you know, when we were there for the technical conferences, that they're more than willing to work with us on exploring what other options could be there, what things that we could do to mitigate some of the operational impacts. So we are planning to do that. We hope to get this thing kicked off this month and establish some kind of a working group to go look at, at some of these issues.

So I think your list of potential solutions is certainly a good starting point, and we could pick up from there and, and work on those.

Other things such as the, where you're asking us to modify our AGC algorithm, certainly what you say hits a sweet spot for us as something we would really like to look at. You didn't label anything as research required. It would certainly indicate to us that I think we need to do some additional modeling and thinking about what that looks like, and I suspect that has a research component, before we go modify our AGC algorithm. In the meantime, there are also things that are happening at NERC that are changing the control performance requirements for control area operators, and I think all of that is moving at the same time as to what we have to do.

In addition to that, I thought that the meeting kicked off very nicely with this idea of what Jim Caldwell talked about, which is what is going on elsewhere in the world. Certainly when we went to the -- conference recently, about a month ago, there was a lot of international participation and a lot of information that was coming out of Ireland. And Ireland plans to go to where they have more than 100 percent of their generation covered by wind generation. Everybody sees that as a very rich, windy area, I guess.

So the, and they've done a tremendous amount of putting together detailed models on all the different types of wind generating units. So I think collaboration and, and tracking of what's going on in the international level, as well as the national level, also will provide a real valuable input to us as we do our studies here. I think California is unique and, and very fortunate in that we also have a lot of hdyro resources that we can have, do a lot of flexible things with, that other areas do not. And I think as we look at also the variability of wind, we also have to look at the fact that the hydro resources sometimes, like this year, fortunately, we're going to be what, 140 percent of normal, some years we're at 70 percent of normal.

So how do we look at a resource mix where we have a number of things that gives us great variability, but also gives us the ability to do a lot of ramping and storing, storage, and looking at holding back water during different periods in order to get some really good energy storage. So I think new techniques of looking back again at these, these kinds of optimization techniques for making the maximum utilization of all the resources are really going to be part of that overall plan.

So I think we would be very much committed to doing the implementation and providing the resources. Timetable to do this in, boy, that's a good guess. I'd like to sit down with the working group and come out with some detailed plans as to what we're going to do, and then tell you the timeframe.

MR. DYER: Thank you, Dave.

Jorge, any comment?

MR. CHACON: From an implementation respect, I mean, the first question deals with would we, would we support and sponsor, you know. I think Edison would support the implementation, so we're certainly glad to hear Dave here suggest a working group. I think that's a great, a great idea, a great starting place. Sponsoring, I, I don't know that, you know, Edison is in a position to sponsor anything right now. I think we all need to learn and grow together and figure out what needs to be done before you can, you know, put the hammer on the nail and say we're going to sponsor this. So I think there's a lot of learning yet to be done that we need to go through, and if we do come up with a, a pertinent solution we'd be more than happy to sponsor that.

So with that regard, I mean, you know, there's, there's ten solutions here. I think they're all great. Some of them are, are ISO specific. Some of them are regional, WECC or FERC specific, such as the market re-design. Some of them are, are generator specific, you know, the curtailment issue. You know, I don't know that we can sponsor a curtailment. We'd support it, but if the renewables don't want to sign a curtailment contract, I mean, there's nothing we can do.

But all said and done, I think the ten solutions are appropriate. I think we would be more than happy to support those, and we look forward to working with the ISO and PG&E and SMUD, and whoever else is in this working group to develop the best mitigation for the state of California.

MR. DYER: Thank you, Jorge.

Chifong.

MS. THOMAS: I would agree with Jorge and, and Dave that yes, PG&E would support more research, more studies to develop an understanding on what we're looking at and get our, our arms around the problem. And then we can devise solutions.

As far as the solutions are concerned, they are reasonable. Of course, one thing that we need to bear in mind is that when we start talking about curtailment, I understand that a lot of times you could, you could get either a transmission problem by curtailing say, for example, some energy, renewable energy. But we also have to realize that we, the utilities are supposed to take 20 percent of the energy from renewables. So when we start curtailing too much, then we could be running into another problem. So we don't want to back ourselves into from one problem and into another problem.

So yeah, we look forward to working with the ISO and anybody in the industry who would be interested to devise solutions.

MR. DYER: Thank you.

MR. MURLEY: We also -- excuse me -- would look forward to working with the ISO and the IOUs to characterize these problems, define them, develop solutions, work collaboratively, share whatever comes out of our wind integration study, and frankly, would seriously be interested in the other entities sort of, you know, paying a lot of attention to what's going on here in, in our study. We have kind of a microcosm of the state in some respect. We have a lot of hydro, and we're going to look into storage. We're building wind, perhaps in multiple locations.

So I think there can be a lot of spillover benefits, and look, I very much look forward to working together with the groups.

MR. DYER: Do we have -- Commissioner, do you have time for public comments?

CHAIRPERSON GEESMAN: Yeah, I'd like to get comments from the audience if there are any.

Steve.

MR. MUNSON: Steve Munson, Vulcan Power.

Would it be possible to, on the off chance that the, just on the off chance that the projections of 5500 megawatts of wind are not correct for some reason, and only a thousand megawatts of, of baseload are not correct, for some reason, to perhaps switch this model and run it with 2,000 megawatts of baseload and 2750 of wind. And I think that's advisable because trying to manage a gigawatt of, of these required back-ups that may come because of a massive increase in intermittence, it's a good idea to look at what happens if we, if we have massive, substantial baseload. I would ask that you would consider running that same model with --

Second, I'm not sure that the parties have yet looked at the production output diagrams from The Geysers. I think The Geysers does provide a substantial ramping, and I would suggest that they look at that. It's quite easy to do. I don't know if anybody from Calpine is here, but I think, I think The Geysers are providing load support, load following characteristics.

The third thing would be, Commissioner Geesman asked what type of resources for the future are you looking at to fill our reserve requirements. Has anybody looked at the use of perhaps bio-mass and/or geothermal as a reserve? I suggest that may offer some interesting possibilities. A bio-mass plant operates with three months of fuel supply sitting in the yard, and you get some pretty substantial economies of scale. For example, roughly, very roughly, 20 people could run 30 megawatts and 25 or 28 people can run double that, and therefore you might be able to put bio-mass plants in place. Utilize some of this forest thinning money from the federal government and have some reserve standby from bio-mass. Just something to look at.

Thank you for the opportunity.

CHAIRPERSON GEESMAN: Thanks, Steve.

Steven Kelly.

MR. KELLY: Thank you, Commissioner. Steven Kelly, with Independent Energy Producers Association.

Just a couple of observations, and I appreciate this, this study work that's already been done. It appears when you first read it there's some huge problems with the integration of renewables because of all the things that are going to happen when they scale up as they've, they've done. But one sense that I get, or one observation is that under the least cost best fit methodology that's being used both for renewables and apparently both for the non-renewables, my assumption is that many of these problems should be going away as the utilities plan their system, when they buy resources to mitigate the negative impacts of new generation. So I have, I presume that a lot of these effects will not occur by 2010 if they design their system properly.

And that leads me to my second observation, which is that there's so far, kind of a -- we haven't really addressed the integration of the state's two procurement policies, which are the resource adequacy policy integrated with the RPS. And I think for this thing to move forward there needs to be some consideration or study work on how those are going to meld together, because here again, I presume that if the resource adequacy implementation is done properly, whether it's going to be 115 percent of capacity to serve load, planning reserves and operational reserves, a lot of the problems that are being projected in this study should be handled through, you know, the acquisition of non-renewables for ramping rolls, and so forth.

So it seems like we're divorcing those two policies, and they ought to be integrated together. And I think here again, you'll find potential for minimizing the effects of meeting the 20 or 30 percent renewable requirement. What that really means is you've got either 70 or 80 percent of the resources being non-renewable. And we can procure those in such a way to mitigate a lot of these effects.

And then my third observation is that this just speaks for the, the need for transparency in the planning and procurement process. What's lacking today is any transparency on how the load serving entities are going about identifying what they need, when they're going to need it, and so forth. And I know, Commissioner Geesman, you've raised this issue, and I echo it strongly, that there needs to be more transparency in that process. Unfortunately, it does not look like that transparency is going to emerge at the Public Utilities Commission, which has authority over the IOUs. It properly is probably situated is here at the Energy Commission now because of the integration of the, of the munis with the load serving entities on a region-wide basis, and I just urge you to continue your efforts to make more transparent the planning and procurement steps that will be used so that we can see the integration of the resource adequacy requirement with the RPS requirement in a more, more open way.

Thank you.

CHAIRPERSON GEESMAN: Thank you, Steven.

MR. SIMS: Robert Sims with AES SeaWest.

Actually, I have a question for Bob Zavadil, from his presentation earlier this morning, and asking to put the challenge of integrating intermittent resources into California in perspective as compared to other areas of the country that you're studying, or even other parts of the world.

My expectation is that the thermally driven winds in California are more conducive to forecasting our generation mix of hydro and pumped hydro opportunities and, and more thermal generation that really California is in an enviable position as compared to other parts of the country that are looking primarily at coal-fired generation and other types of generation such as NSP. So I just wondered if you had an opinion about that.

MR. ZAVADIL: Thank you, Rob.

(Laughter.)

MR. ZAVADIL: I was off duty already.

I, I think the things you mentioned are, are intriguing, you know, from the standpoint of resource diversity and some of the things that are unique about California. The thing that gives me qualms, however, is, is sort of the enormity of the problem. I mean, we're talking about a, a very large system both in terms of capacity energy as well as land area. And so while it, you know, may be somewhat easier to forecast, you know, wind generation in certain areas, whether that applies, you know, uniformly across the state I, I wouldn't want to conjecture on that.

So I, I think, you know, hydro resources, diversity of resources, diversity of land area, all those things, you know, add -- potentially help you. But, but I wouldn't want to make, draw any conclusions, you know, without actually running through, running through the numbers.

CHAIRPERSON GEESMAN: Hal.

MR. ROMANOWITZ: Thank you. Hal Romanowitz, Oak Creek Energy.

I just wanted to say that I think in particular the approach that Dave Hawkins has laid out is I think extremely helpful, that the process that has worked with CAISO and the PERK program before, for example, has been extremely beneficial, where you get broad-based input, and I think that you'll see many of the problems that have been described here as potential and maybe even figments of the, you know, the way the data was, you know, sort of created for 2010, that a lot of these things would just go away. And I think we can find some very good solutions.

CHAIRPERSON GEESMAN: Anyone else?

Nancy.

MS. RADER: Hi, good morning. Nancy

Rader with the California Wind Energy Association.

I just wanted to congratulate the group for really taking the comments that you received to heart. It's, I see this report as dramatically different from the first draft, which was sort of the sky is falling, the sky is falling quality, to this one, which presents a large amount of intermittence as a manageable problem, which we think it is. So I really appreciate that dramatic improvement.

I'm still a little concerned that based on the, the comments made by some of the utility representatives that they're not getting the message of this report and many others that, that wind may not be a perfect fit, but the cost of integration is very low, and manageable. So this notion that somehow wind is not going to fit later on I think is incongruent with the message of this report.

And I just wanted to ask you a question. I just wonder how this work is being coordinated with the RPS integration studies that are, that I guess are on a parallel track. Those studies do follow the Oak Ridge and NREL robust methodologies that I think SMUD was referring to, and so I'm still unclear myself as to how these two efforts are being coordinated.

CHAIRPERSON GEESMAN: No less so than me right now. We had hoped to have the Phase 2 of the report that, that you've described in public workshops earlier this year. For a number of reasons, most of which I don't understand, that appears to have been delayed. Staff continue to work on it, and if they are able to complete the work on Phase 2 in time we will work it into our workshop schedule in this cycle.

So I don't know if characterizing it as a parallel effort is any longer an accurate description or not. And they don't let me supervise the staff.

MS. RADER: Is, is there discussion, though? Is -- are you talking to them? Is there, you know, I just, I guess I hope the two groups are talking and coordinating.

CHAIRPERSON GEESMAN: There, there is some discussion between the staffs.

MS. RADER: Okay. Thank you.

CHAIRPERSON GEESMAN: Jim.

MR. CALDWELL: I'd just like to make one quick suggestion for a follow-on, and that is, is that it's clear that we're going to do more studies. I mean, I don't think there's anybody who's saying that, that A, we know everything, or even if some of us think we might know most of everything, that everyone doesn't know. And that people are going to have to do a lot more studies before they're comfortable. And I think the customers have said that here, when you look at it.

And I would suggest that, that the ongoing studies, that we focus those studies on a real problem and a real issue, and that, that I don't think that more generic studies or more sort of 10,000 foot studies are really what we need. We've done those. We know what those answers are. Those answers are we have nothing to fear from moving ahead.

But the answers also say, and the studies also say, that we need to do something specific and something real. And I would suggest that I don't know of any other place to say that, and that ought to be Tehachapi. I mean, that is, if that is the gold mine for, for wind here, let's go ahead and let's do the study that people want, that SMUD talked about, that George talked about.

Let's do that for Tehachapi, and let's do it in collaboration, not just a few of us, but all of us together, and let's do that.

So that was my suggestion.

CHAIRPERSON GEESMAN: Thank you.

MR. LaFLASH: Hal LaFlash, PG&E, Resource planning.

You had asked Chifong earlier if there's somebody here from the procurement side, so I thought I'd step up there on the least cost best fit issue. And I'd also like to reiterate the importance of the integration studies that are coming up, because while the integration costs may be low in, in some perception, there has to be a difference between integrating intermittent and integrating baseload. And we'd like to see that reflected, and that will help our least cost best fit analysis if we can make a proper comparison between the wind resource and a firm RA capacity resource like the geothermal or bio-mass.

So I just wanted to add that vote.

CHAIRPERSON GEESMAN: Gary.

MR. ALLEN: Gary Allen, with Southern California Edison.

Thanks, Hal. Appreciate your comments.

I guess along that same line, it seems to me that yes, the system can manage all of these various parameters that we're talking about here. But everything we've talked about, all of Jim's solutions seem to me things that will cost money. And each of those will be things that will be an integration cost, of sorts. So I don't want to miss that in the broad picture. There are going to be integration costs, and these are some of the things that we've been talking about.

CHAIRPERSON GEESMAN: No question about that.

MR. SMITH: Good afternoon. I'm Mark Smith, I'm with FPL Energy.

We'd like to build more wind projects in California. We'd like that very badly. And hearing what I've heard today, there really is much to agree with. The two things that I think can drive and clarify our purchase decisions going forward, I think, as Mr. Hawkins telegraphed, are defining the problems with the precision necessary to be able to make them actionable. And there are two things that can do that.

The first is the high penetration, fully constrained network analysis of California and what kinds of impacts will arise, as NYSERDA has done. And the second, again, going by what Mr. Hawkins said, is the detailed analysis of the problems that have been experienced to date, whether they be high speed cut-out, or whatever they might be, and defining them with precision so that we can go to the manufacturers and engineers and say solve this problem so that it's not a problem two years when we receive delivery on the equipment we'd like to build.

Thank you very much.

CHAIRPERSON GEESMAN: Thank you.

Other comments from the audience.

MR. FERGUSON: I'm Rich Ferguson, CEERTS. Since Jim brought up Tehachapi, I have to say one of the things that we got criticized for in the study group was the lack of a look at the hydro system. And I agree with Jim that we need to sort of focus down on some real problems and find out, you know, exactly what we need and how much that's going to cost before we just sort of say well, it'll be solved with the least cost best fit kind of stuff.

But, I mean, I think everybody in this room would agree that it's time for a new look at the hydro system and how that can be re-operated and, you know, if it's changing, how are we going to -- whatever. And we a lot of criticism because we didn't do that. We didn't have the resources. It wasn't in our charter. But if you wanted my vote or nomination for a project to undertake, it would be take a hard look at about how we can use the hydro system differently in the state to deal with the future resources. Thanks.

CHAIRPERSON GEESMAN: Thanks, Rich.

Other comments? Carl.

MR. WEINBERG: I'm Carl Weinberg, and I just represent myself here at this hearing.

As I mentioned yesterday, I thought we were moving into paralysis by analysis. Nothing I heard today would change that view. Sitting in the back there listening to all this, I tried to dredge up a little bit of the mathematics I still remember from my college days of long ago, which said that if you have an equation with N unknowns and N-plus one variables, it's not solvable. And the suggestions here of, of taking specific examples basically narrows the variables down so that you have a chance to still have a solution. But if you continue to go on with the N unknowns and N-plus one variables, you can't solve them.

CHAIRPERSON GEESMAN: Other comments. That may be a good one to close on.

(Laughter.)

CHAIRPERSON GEESMAN: I want to thank everybody for your participation today.

Don?

MR. KONDOLEON: Yeah. Let me just, some quick housekeeping items. I just want to echo what Commissioner Geesman just said and thank you for your participation. We would like written comments, if you have, on the report, on any of the presentations or the panel discussions, or any of the other comments that you've heard. Can you provide those to us please by close of business May 20th, which would be a week from Friday.

EPG at that time will be looking at the comments, as will staff. They will be developing a final report that'll be delivered to the Commission sometime in early June. That report will be reflected in the staff's transmission report that'll be available in July, and that report in total will be an appendix to that document.

In the meantime, I've been informed by

our PIER renewables colleagues that in fact, they will be moving forward with the EPG work and other work in what they're calling the Intermittency Analysis Project. That project, being led by George Simon, will be coordinated with the California Wind Energy Collaboration.

I don't know much about this other than what I was just told the last couple days about it. I know Dave Hawkins' name shows up on that collaboration list amongst some others here in the audience. But please, if you have any questions about that, I'd refer to George Simon.

And then, finally, the next transmission workshop will be a week from Thursday here at the Commission, on May 19th. We will be emphasizing that discussion on transmission corridors, and then there will be a discussion about the work to date on the development of our activities with regard to the state's first strategic transmission investment plan.

So again, I want to thank you all for participating today, and we look forward to seeing you next week.

CHAIRPERSON GEESMAN: We'll be adjourned.

(Thereupon, the 2005 Energy Report Committee Workshop on Renewable Transmission Operational Issues Update Number 2 was adjourned at 12:18 p.m.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that thereafter the recording was transcribed.

I further certify that I am not of counsel or attorney for any of the parties to said Committee Workshop, or in any way interested in the outcome of said Committee Workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 20th day of May, 2005.